HYDRO ONE INC.
ANNUAL CONSOLIDATED FINANCIAL STATEMENTS

	Page
Management's Discussion and Analysis	2
Management's Report	38
Independent Auditors' Report	39
Consolidated Statements of Operations and Comprehensive Income	40
Consolidated Balance Sheets	41
Consolidated Statements of Changes in Shareholder's Equity	43
Consolidated Statements of Cash Flows	44
Notes to Consolidated Financial Statements	45
Five-Year Summary of Financial and Operating Statistics	92

HYDRO ONE INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

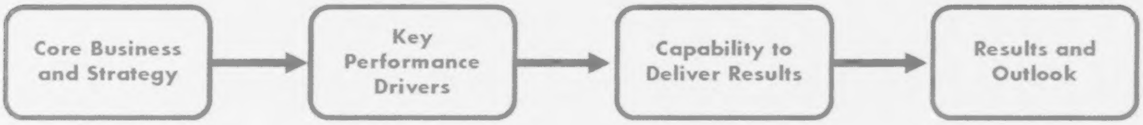
On January 1, 2012, Hydro One Inc. (Hydro One) adopted United States (US) Generally Accepted Accounting Principles (GAAP) as its approved basis for accounting and financial reporting. Comparative 2011 information is presented under US GAAP, unless otherwise noted. All amounts are in Canadian dollars.

The following discussion is based on our Consolidated Financial Statements for the years ended December 31, 2012 and 2011.

EXECUTIVE SUMMARY

We are wholly owned by the Province of Ontario (Province), and our transmission and distribution businesses are regulated by the Ontario Energy Board (OEB). Our mission and vision has been refined to recognize the unique role we play in the economy of the province and as a provider of critical infrastructure to all our customers. We strive to be an innovative and trusted company, delivering electricity safely, reliably and efficiently to create value for our customers. We operate as a commercial enterprise with an independent Board of Directors. Our strategic plan is driven by our values: health and safety; excellence; stewardship; and innovation. Safety is of utmost importance to us because we work in an environment that can be hazardous. We take our responsibility as stewards of critical provincial assets seriously. We demonstrate sound stewardship by managing our assets in a manner that is commercial, transparent and which values our customers. We strive for excellence by being trained, prepared and equipped to deliver high-quality service. We value innovation because it allows us to increase our productivity and develop enhanced methods to meet the needs of our customers. In 2012, we continued to focus on our core businesses and our commitment to our customers and made important contributions to the rebuilding of Ontario's core infrastructure while continuing to meet the requirements of the Green Energy Act (GEA).

We manage our business using the following framework:



Core Business and Strategy

Our corporate strategy is based on our mission and vision and our values. Our strategic goals, which are discussed in the section "Our Strategy," encompass the core values that drive our business. Our strategy touches every part of our core business: health and safety; our customers; innovation; the reliability and efficiency of our systems; the environment; our workforce; shareholder value; and productivity.

Key Performance Drivers

Performance drivers have been identified that relate to achieving certain of our company's strategic goals. We establish specific performance targets for each driver aimed at measuring the achievement of our strategic goals over time. For example, we track the duration of unplanned customer interruptions per delivery point as an indication of our commitment to provide a reliable transmission system for our customers. We measure transmission and distribution unit costs as an indication of our commitment to increasing productivity. These and other key performance drivers are included in our discussion of our performance measures in the section "Performance Measures and Targets."

Capability to Deliver Results

We continue to use a balanced scorecard approach as we strive to manage our performance and deliver results each and every year. In 2012, we set nine stretch targets and we met or exceeded five of them. In 2011, we met or exceeded 13 of 17 stretch targets. We exceeded our target for minimizing the duration of unplanned customer interruptions within our Transmission Business. Our performance with respect to productivity was on target in our subsidiary Hydro One Networks Inc.'s (Hydro One Networks) transmission and distribution businesses. Our ability to deliver results in each of our strategic areas is limited by risks inherent in our regulatory environment, our business, our workforce and in the economic environment. These risks, as well as our strategies to mitigate them, are discussed in the section "Risk Management and Risk Factors."

Results and Outlook

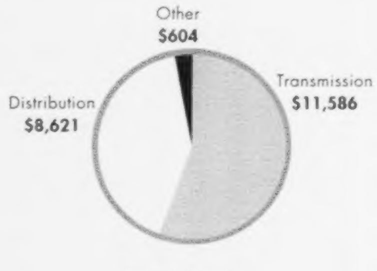
During 2012, our financial fundamentals remained strong with current year net income of $745 million. Our OEB-approved revenue requirement for our transmission business for 2012 was $1,418 million. Our 2011 distribution rates for Hydro One Networks continued unchanged throughout 2012, and its approved revenue requirement for 2011 was $1,218 million. Approved rates support the work programs required to sustain our critical infrastructure and invest in a sustainable electricity system that supports renewable and cleaner generation. We successfully issued $1,085 million in debt financing in 2012, the proceeds of which were used to fund the retirement of $600 million of debt maturing in the year and to fund a portion of our capital expenditures and other corporate requirements. A full discussion of our results of operations and financing activities can be found in the sections "Results of Operations" and "Liquidity and Capital Resources."

In 2012, we invested more than $1.4 billion in capital expenditures to improve system reliability and performance, address our aging power system, facilitate new generation and improve service to our customers. Capital expenditures for the next few years will include those required to build critical infrastructure identified in the Long-Term Energy Plan (LTEP), which is based on recommendations from the Ontario Power Authority (OPA), and expenditures to address aging infrastructure. Our future capital expenditures are more fully described in the section "Future Capital Expenditures."

OVERVIEW

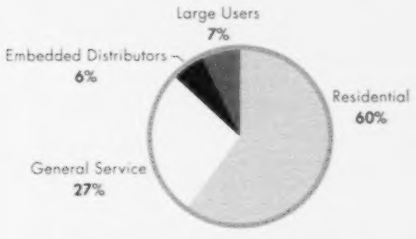
Transmission

Substantially all of Ontario's electricity transmission system is owned and operated by our subsidiary Hydro One Networks. Our transmission system forms an integrated transmission grid that is monitored, controlled and managed centrally from our Ontario Grid Control Centre. Our system operates over relatively long distances and links major sources of generation to transmission stations and larger area load centres. In 2012, we earned total transmission revenues of $1,482 million, primarily by transmitting approximately 141 TWh of electricity, directly or indirectly, to substantially all consumers of electricity in Ontario. Our transmission system is one of the largest in North America, and it is linked to five adjoining jurisdictions through 26 interconnections, through which we can accommodate imports of about 4,800 MW and exports of approximately 6,000 MW of electricity. In terms of assets, our Transmission Business is our largest business segment, representing approximately 56% of our total assets at December 31, 2012.



Total Assets
December 31, 2012
(CAD $ millions)

Distribution



2012 Distribution Revenues

Our consolidated distribution system is the largest in Ontario and it spans roughly 75% of the province. We serve approximately 1.4 million rural and urban customers and 440 large user customers. Our subsidiary Hydro One Remote Communities Inc. (Hydro One Remote Communities) operates small, regulated generation and distribution systems in a number of remote communities across northern Ontario that are not connected to Ontario's electricity grid. In 2012, we earned total distribution revenues of $4,184 million. As illustrated in the accompanying chart, over half of our distribution revenues were earned from our residential customers. At December 31, 2012, our Distribution Business assets represented approximately 41% of our total assets.

Other

In 2012, our Other business segment contributed revenues of $62 million, and had assets of $604 million at December 31, 2012, representing 3% of our total assets. This segment primarily represents the operations of our wholly-owned subsidiary, Hydro One Telecom Inc., which markets fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements, including a dedicated optical network providing secure, high-capacity connectivity across numerous health care locations in Ontario.

Our Strategy

Our corporate strategy is based on our mission and vision and our values. Our mission and vision is to be an innovative and trusted company delivering electricity safely, reliably and efficiently to create value for our customers. Our values represent our core beliefs:

Health and safety: Nothing is more important than the health and safety of our employees, those who work on our property, and the public.

Excellence: We achieve excellence through continuous training, ensuring we are prepared and equipped to deliver high-quality and cost-effective service, with integrity.

Stewardship: We invest in our assets and people to build a safe, environmentally sustainable electricity network in a commercial manner.

Innovation: We innovate through new processes, people and technology to allow us to find better ways to meet the needs of our customers.

We have eight strategic objectives that are inextricably linked. They drive the fulfillment of our mission and vision.

Creating an injury-free workplace and maintaining public safety. Health and safety must be integrated into all that we do. We must continue to create a passion for preventing injury. We will strengthen our already strong safety culture through our Journey to Zero initiative and achieve world-class results. We will implement the internationally recognized health and safety management system, ISO 18001, to identify health and safety risks, priorities and mitigation in order to further drive our safety culture. We will continue to reinforce that nothing is more important than the health and safety of our employees.

Satisfying our customers. We will meet our commitments, make customers our focus in our planning, communicate effectively, coordinate across lines of business, and maximize opportunities to improve our corporate image. We will develop and deliver targeted customer segment strategies, products and delivery channels that will respond to their unique needs and behaviours.

Continuous innovation. Innovation represents one of our core values and is critical to achieving our mission and vision. Over the next two decades, we will install innovative solutions that improve the reliability and efficiency of the transmission and distribution systems and provide our customers with more capability to manage their power costs. The Advanced Distribution System (ADS) is a key element in our investment in innovation and will improve operation of our distribution assets and deliver further value to our customers.

Building and maintaining reliable, cost-effective transmission and distribution systems. Our transmission strategy is to provide a robust and reliable provincial grid that accommodates Ontario's emerging generation profile, manages an aging asset base and meets demand requirements through prudent expansion and effective maintenance. Our distribution strategy is focused on: incorporating ADS technology to provide greater visibility; increasing control and improving customer service; supporting the connection of renewable energy sources; seeking efficiencies through leveraging technology and operational experience from our transmission system; providing reliable and cost-effective service over a diverse geography; and pursuing commercial arrangements that are anticipated to arise from the rationalization of Ontario's distribution sector.

Protecting and sustaining the environment for future generations. Consistent with our value of stewardship, we play a central role in reducing Ontario's carbon footprint through the delivery of clean and renewable energy and through measures that allow our customers to manage and reduce their energy use. We will engage our customers further regarding how we manage our sustainability obligations and activities on their behalf.

Employee engagement. We believe our primary strength is the capability of our people. In order to sustain this advantage, we must address the issues of corporate culture, labour demographics, diversity, development of critical core competencies and skill and knowledge retention. Our labour strategy should enable us to make significant gains in the areas of labour flexibility, productivity improvement and cost reduction.

Maintaining a commercial culture that increases value for our shareholder. We are committed to keeping rates as low as possible for our customers, and delivering income and dividends to our shareholder. This is possible through our focus on reducing costs, managing our assets effectively and increasing productivity. We will explore and pursue opportunities to increase the revenue-earning potential of our company by leveraging existing assets, technologies, capabilities and the geographic presence of our company.

Achieving productivity improvements and cost-effectiveness. To achieve our mission and vision, we must constantly strive for productivity through efficiency and effective management of costs. Productivity is key to meeting our other strategic objectives and, in particular, to achieving value for our customers and our shareholder.

We recognize the pivotal role innovation will play in building a smart electricity grid that supports a clean environment for Ontario. We are committed to becoming the industry leader in putting innovative solutions to work for the well-being of Ontario's economy and its residents.

Performance Measures and Targets

We target and measure our performance by using a balanced scorecard approach. Key performance drivers are closely monitored throughout the year to ensure that we maintain a focus on our strategic objectives and take mitigating actions as required. In 2012, we met or exceeded five of nine stretch targets. Overall, we are making progress towards achieving many of our strategic goals.

Achieving productivity improvements and cost-effectiveness

One of our strategic objectives is to increase productivity through efficiency improvements and effective management of costs. The measures for this objective for 2012 were transmission unit cost and distribution unit cost.

For 2012, we measured for transmission unit cost the capital expenditures and operation, maintenance and administration costs per dollar of gross in-service assets (expressed as a percentage). For distribution unit cost, the measure is capital expenditures and operation, maintenance and administration costs per kilometre of line ($'000/km) due to the length of line required to connect our rural customers. Our objective with our ongoing work and investment program is to maintain and improve our assets and monitor our productivity year-over-year. Our transmission unit cost target was set at 10.1% and we met this target. The distribution unit cost target was set at $11,000 per kilometre of line and we also met this target.

Building and maintaining reliable, cost-effective transmission and distribution systems

We continue to build and retain public confidence and trust in our operations, as stewards of Ontario's electricity grid. In 2012, we continued our focus on this strategic priority by investing in the key assets of the electricity delivery system and by operating the existing system for customers in a safe, reliable and efficient fashion. We are conscious that commercial customers of all sizes require reliable service to allow them to deliver their products and services and that customers' expectations are for a reasonably limited duration when interruptions occur. Transmission and distribution reliability is measured through the duration of customer interruptions.

For the duration of unplanned customer interruptions within our Transmission Business, the target for 2012 was 10 minutes per delivery point. We more than met this target.

For the Hydro One Networks distribution business, the target for 2012 for the duration of customer interruptions was set at 6.7 hours per customer. We did not meet this target.

Satisfying our customers

Customer satisfaction measures the degree to which our transmission and distribution customers are satisfied with the service they receive from our company. Customer satisfaction is based on the results of customer surveys conducted on our behalf by independent third parties. In 2012, for transmission customers we targeted a customer satisfaction rate of 90%, but did not meet this target. For our distribution customers, we targeted a satisfaction rate of 86%, and we met this target.

Employee engagement

We continue to focus efforts on increasing employee engagement throughout the company. An engaged workforce is one in which employees embrace the corporate values of safety, stewardship, excellence and innovation. The process of measuring and improving such engagement began in 2008 by means of an employee engagement survey administered by an independent third-party expert. Our goal is to improve the grand mean score year-over-year. The target of improving the grand mean score to 4.06 (out of 5) in 2012 was not met.

Maintaining a commercial culture that increases value for our shareholder

Achievement of strong financial performance is measured by a performance measure of targeted level of net income after tax. Our target was $643 million net income after tax and we exceeded our target.

Creating an injury-free workplace and maintaining public safety

The safety of our employees is paramount. In 2012, we used medical attentions, defined as injuries that require treatment by a medical practitioner (beyond first aid), as the performance measure for this strategic objective. The medical attentions measure reflects incidents that are reported to the Workplace Safety and Insurance Board and is calculated as the number of attentions per 200,000 hours worked. In 2012, Hydro One set a target of no higher than 2.2 attentions per 200,000 hours worked. In an effort to achieve this target, we engaged in a number of activities, such as: continued emphasis on improving health and safety through face-to-face sessions; continuation of our Journey to Zero initiative; better monitoring of mandatory skills and safety training; an enhanced driver training/evaluation program; and field coaching to increase the expectations from supervisors and staff. The number of attentions in 2012 improved by 35% compared to the number in 2011 but was still slightly higher than our target for 2012.

REGULATION

Our electricity transmission and distribution businesses are licenced and regulated by the OEB. The OEB sets rates following oral or written public hearings. Our transmission revenues primarily include our transmission tariff, which is based on the province-wide uniform transmission rates (UTRs) approved by the OEB for all transmitters across Ontario. Our distribution revenues primarily include our distribution tariff, which is also based on OEB-approved rates, and the recovery of the cost of purchased power used by our customers. Consequently, our Distribution Business does not have commodity price risk. Transmission and distribution tariff rates are set based on an approved revenue requirement that provides for cost recovery and a return on deemed common equity. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory accounts over specified timeframes.

Electricity Rates

Under the current market structure, low-volume and designated consumers pay electricity rates established through the Regulated Price Plan (RPP) and wholesale electricity consumers pay a blend of regulated, contract and wholesale spot market prices. The OEB sets prices for RPP customers based on both a two-tiered electricity pricing structure, with seasonal consumption thresholds, and a three-tiered electricity pricing structure with Time of Use (TOU) thresholds. The majority of our RPP customers are now on TOU billing. Unexpected shortfalls or overpayments associated with the RPP are temporarily financed by the OPA. Prices are reviewed by the OEB every six months and may change based on an updated OEB forecast and any accumulated differences between the amount that customers paid for electricity and the amount paid to generators in the previous period.

We started migrating our customers to TOU rates in 2010 and the majority of our customers were transitioned to TOU rates by the end of 2011. We received an exemption from the OEB, effective until December 31, 2014, from implementing mandatory TOU pricing for approximately 120,000 customers that are currently out of reach of our smart meter telecommunications infrastructure.

Customers who are not eligible for the RPP and wholesale customers pay the market price for electricity, adjusted for the difference between market prices and prices paid to generators by the Independent Electricity System Operator (IESO) under the *Electricity Act, 1998*. The IESO is responsible for overseeing and operating the wholesale market as well as ensuring the reliability of the integrated power system.

Transmission Rates

The IESO facilitates payments to us based on the Ontario UTRs approved by the OEB for all transmitters across Ontario.

On May 19, 2010, we submitted our application for 2011 and 2012 transmission rates in continued support of our aging critical infrastructure and supply mix objectives for generation, including off-coal initiatives and initiation of investments in support of the GEA. This application sought the approval of revenue requirements of approximately $1,446 million for 2011 and $1,547 million for 2012, which represented estimated rate increases of 15.7% and 9.8%, respectively, or 1.2% and 0.7% on an average customer's monthly bill.

On December 23, 2010, the OEB issued its decision, which resulted in a revenue requirement effective January 1, 2011 of $1,346 million for 2011 and $1,658 million for 2012, reflecting transmission rate changes of approximately 7% in 2011 and 26% in 2012, or 0.5% and 2%, respectively, on an average customer's total bill. Our 2012 revenue requirement was impacted by the OEB directing us to adopt a cost capitalization policy consistent with International Financial Reporting Standards (IFRS). This specific accounting revision resulted in an increased revenue requirement of about $200 million for 2012.

Consistent with an approval from the Ontario Securities Commission (OSC) to adopt US GAAP for our external financial reporting and securities filings, on July 15, 2011 we filed a Motion to Vary the OEB's 2012 rate decision. Our application sought approval to adopt US GAAP as a basis for regulatory accounting and rate setting in place of the OEB's approved modified IFRS basis. On November 23, 2011, the OEB approved the use of US GAAP by our Transmission Business, which resulted in the reversal of the $200 million adjustment that was made by the OEB in its December 2010 rate decision.

On December 1, 2011, we submitted to the OEB a draft 2012 transmission revenue requirement that reflects the approved adoption of US GAAP for rate-setting purposes as well as the OEB-directed update to 2012 cost-of-capital parameters. On December 20, 2011, the proposed $1,418 million 2012 revenue requirement was approved by the OEB along with new 2012 UTRs effective January 1, 2012. The new rates resulted in an approximate 8% transmission rate increase, or 0.6% on an average customer's total bill. The adoption of US GAAP in lieu of modified IFRS as a basis for rate setting decreased the approved rates by about 15%.

To achieve the necessary funding in support of aging critical infrastructure and investments, we submitted a cost-of-service rate application to the OEB for our 2013 and 2014 transmission rates on May 28, 2012. The application sought OEB approval for revenue requirement increases of approximately 0.6% and 9.1% in 2013 and 2014, respectively, or estimated increases of 0% in 2013 and 0.7% in 2014, on an average customer's total bill. A settlement conference was held in October 2012, where Hydro One Networks and the intervenors reached an agreement, settling all issues apart from Export Transmission Service. This is anticipated to be settled in early 2013 but is not expected to affect our company's results of operations. The settlement agreement was reviewed and approved by the OEB on November 8, 2012. On November 30, 2012, we submitted a draft rate order, which includes revenue requirements of approximately $1,438 million and $1,528 million for 2013 and 2014, respectively. For the transmission portion of the bill, this represents no change from existing 2012 OEB-approved rate levels in 2013 and a 5.8% increase in 2014. On an average customer total bill basis, this represents increases of nil for 2013 and 0.5% for 2014. On December 20, 2012, the OEB issued a final Rate Order, approving Hydro One Networks' 2013 transmission revenue requirement for use in setting the 2013 Ontario UTRs.

Distribution Rates

As a distributor, we are responsible for delivering electricity and billing our customers for our approved distribution rates, purchased power costs and other approved regulatory charges. Substantially all of our purchased power costs and other approved regulatory charges are settled through the IESO, which facilitates payments to other parties such as generators, the Ontario Electricity Financial Corporation (OEFC) and itself.

In 2006, the OEB established a multi-year electricity distribution rate-setting plan whereby a distributor's rates are set via a cost-of-service rebasing application followed by an Incentive Regulation Mechanism (IRM) that uses a formulaic approach to establish rates for the next three years. In 2012, the OEB issued a new regulatory framework that included three rate-setting methods available to distributors (see "Renewed Regulatory Framework").

Hydro One Networks

On July 13, 2009, our subsidiary Hydro One Networks filed a cost-of-service application with the OEB for 2010 and 2011 distribution rates.

On April 9, 2010, the OEB released its decision approving revenue requirements of $1,146 million for 2010 and $1,236 million for 2011 to support the necessary work programs, the implementation of the GEA and the installation of smart meters.

On November 15, 2010, the OEB issued its cost-of-capital parameter updates for rates effective January 1, 2011. The lowering of the return on equity (ROE) produced a revised revenue requirement of $1,218 million. The approved 2011 revenue requirement resulted in an average distribution rate increase of approximately 8.7% for 2011, or 3.4% on an average (i.e. consuming 800 kWh per month) customer's total bill.

On March 23, 2012, the OEB approved our request for Hydro One Networks' distribution business to adopt US GAAP for rate setting and regulatory accounting and reporting. Hydro One Networks did not seek a distribution cost-of-service rate adjustment for 2012 and rates continued unchanged at 2011 levels.

On June 15, 2012, Hydro One Networks filed evidence in support of its application for 2013 distribution rates on the basis of the OEB's 3rd Generation IRM process. Hydro One Networks and intervenors subsequently reached a settlement and submitted a settlement agreement to the OEB. On December 14, 2012, the OEB issued its decision accepting the agreement as filed. On December 20, 2012, the OEB issued a final Rate Order. The distribution rate of an average residential customer will increase by approximately 1.3% in 2013, or by 0.4% when considering total bill impacts. In addition, the Retail Transmission Service Rates adjustment, which was accepted in the Settlement, will bring the total bill increase in 2013 to approximately 1.5%.

Hydro One Brampton Networks

On June 30, 2010, our subsidiary Hydro One Brampton Networks submitted its 2011 cost-of-service application, which was subsequently adjusted in September to reflect the optional deferral of the adoption of modified IFRS until January 1, 2012, consistent with a decision by the Canadian Accounting Standards Board (AcSB). The AcSB later extended the optional deferral to January 1, 2014 and Hydro One Brampton Networks has decided to exercise this option.

Following another adjustment to the application in November 2010, the revenue requirement was approximately $63 million. On April 4, 2011, the OEB issued a decision that approved a revenue requirement of $59.5 million for 2011. The revised rates were approved with an effective date of January 1, 2011 and an implementation date of May 1, 2011. Included in the rates is an amount of $1.52 per month per metered customer for smart meters and approval of a GEA funding adder of $0.02 per month per metered customer. The new rates result in a total bill increase for an average customer (i.e. consuming 800 kWh per month) of approximately 0.5%.

On September 15, 2011, Hydro One Brampton Networks filed an application for 2012 rates on the basis of the OEB's 3rd Generation IRM process. On December 22, 2011, the OEB issued its decision and on December 31, 2011, the OEB declared Hydro One Brampton Networks' existing rates interim as of January 1, 2011. On January 5, 2012, the OEB released a decision that resulted in a reduction in rates of approximately 13.2%, or a 1.7% reduction on the average customer's total bill in the year. These rate reductions were primarily due to OEB-approved adjustments to depreciation rates.

On August 3, 2012, Hydro One Brampton Networks filed an application for 2013 rates on the basis of the OEB's 3rd Generation IRM process, requesting new distribution rates effective January 1, 2013. Hydro One Brampton Networks subsequently amended its rate application and on December 6, 2012, the OEB approved the amended application. The rate impact on the distribution component associated with a typical residential customer was an increase of approximately 0.3%, or less than 0.1% on the customer's total bill.

Hydro One Remote Communities

On October 15, 2010, Hydro One Remote Communities filed an application for 2011 distribution rates on the basis of the OEB's 3rd Generation IRM. The application sought approval for an increase of approximately 0.4% to basic rates for the distribution and generation of electricity effective May 1, 2011. On March 28, 2011, the OEB approved the application. The overall impact of the new rates on an average (i.e. consuming 800 kWh per month) residential customer's total bill was marginal.

On November 25, 2011, Hydro One Remote Communities filed its application for 2012 distribution rates on the basis of the OEB's 3rd Generation IRM. On March 22, 2012, the OEB issued its decision approving a rate increase of 1.08% effective May 1, 2012, representing an increase of about $1 on an average residential customer's monthly bill.

Consistent with the OEB's decision affirming the use of US GAAP for rate-setting purposes by Hydro One Networks' transmission and distribution businesses, we made a similar request to use US GAAP for Hydro One Remote Communities. On April 3, 2012, the OEB approved the request to use US GAAP as the basis for rate setting within Hydro One Remote Communities effective January 1, 2012.

On September 17, 2012, Hydro One Remote Communities filed a cost-of-service application for 2013 rates to be effective May 1, 2013. If approved as filed, the electricity rate of an average customer will increase by 3.5% in 2013. In its rate application, Hydro One Remote Communities also requested approval to establish a Rural and Remote Rate Protection of $35 million in 2013. The OEB Hearing and decision are anticipated to occur in the first quarter of 2013.

Recent Industry Developments

Long-Term Energy Plan

On November 23, 2010, the Ministry of Energy released Ontario's LTEP, which sets out the province's expected electricity needs until 2030 and supports the continued procurement of new, cleaner generation. The LTEP addresses seven key areas: demand; supply; conservation; transmission; aboriginal communities; capital investments; and electricity prices. On February 17, 2011, the Province issued a Supply Mix Directive that required the OPA to prepare a 20-year Integrated Power System Plan (IPSP) to meet the goals set out in the LTEP. On May 9, 2011, the OPA announced that it was beginning consultations to update Ontario's IPSP and issued the *IPSP Planning and Consultation Overview* document. On June 17, 2011, we submitted our comments on the IPSP, as requested of stakeholders by the OPA. Stakeholder comments will form part of the evidence when the OPA submits the revised IPSP to the OEB for its review.

On February 28, 2011, the OEB issued a decision amending Hydro One Networks' transmission licence in accordance with a directive from the Minister of Energy to the OEB. The licencee amendment requires Hydro One Networks to develop and either seek approvals for, or implement, specified transmission projects and upgrades to safely and reliably accommodate additional renewable energy in accordance with recommendations from the OPA. In a letter dated April 7, 2011, the OPA provided the scope and timing to increase short circuit and/or transformer capacity at ten of 15 transformer stations noted in the licence to accommodate small-scale renewable generation. Six of these upgrades have been completed and we are currently anticipating that one additional station upgrade will be placed in service in 2013. Alternative solutions have been identified for the other three upgrades. In accordance with the Memorandum of Agreement between Her Majesty the Queen in Right of the Province of Ontario as represented by the Minister of Energy (Shareholder) and our company, the Shareholder made a declaration, dated April 19, 2011, pursuant to subsection 108 (3) of the *Business Corporations Act (Ontario)* pertaining to the cost recovery of the expenditures related to the February 28, 2011 licence condition amendment. As a result, the recovery of the seven station upgrades was restricted. We charged $17 million to operation, maintenance and administration expense in 2012 and charged $19 million to operation, maintenance and administration expense in 2011, in respect of these projects.

In June 2011, the OPA recommended the scope and timing of the project to re-conductor two circuits between Sarnia and London, our West of London Transmission Upgrade Project, with a required in-service date of December 2014. This project is needed to satisfy government policy relating to the incorporation of 10,700 MW of non-hydroelectric renewable generation resources by 2018. On November 8, 2012, the OEB issued a decision approving our Section 92, Leave to Construct, application for this project. In October 2011, the OPA recommended the scope and timing of the Southwestern Ontario Reactive Compensation Priority Project, recommending that we install a Static Var Compensator (SVC) at our Milton Switching Station to increase the capability of our Bruce to Milton Line. An OPA recommendation regarding the construction of a new transmission line west of the City of London is not expected in the foreseeable future.

Framework for Transmission Development Plans

On August 26, 2010, the OEB released its new policy entitled *Framework for Transmission Project Development Plans*. This policy sets out a framework for new transmission investment in Ontario by introducing competition for transmission development through an open process. On March 29, 2011, the Minister of Energy expressed the Province's interest in the OEB commencing a transmitter designation process for the East-West Tie Line. The East-West Tie Project is the first transmission network line expansion covered under the new competitive approach. The proposed route is a 400 km, 230 kV double-circuit line between its transformer stations at Wawa in the east and Lakehead in the west. The target in-service date, set by the OPA in its report issued June 30, 2011, is 2017. The East-West Tie LP, an equally-shared partnership of three entities including our company, obtained a transmission licence on May 31, 2012, and is participating in the East-West Tie Project bid process.

The OEB adopted a two-phase process for the East-West Tie proceeding. On July 12, 2012, the OEB issued its Phase 1 decision and order, thus concluding Phase 1 of the proceeding by finalizing various filing requirements and process issues and directing registered transmitters to file their applications for designation by January 4, 2013. The proceeding is now in Phase 2 and the OEB received six applications for designation from the registered transmitters in the proceeding, including one from the East-West Tie LP. The timeline for Phase 2, which will take the form of a written hearing, has not yet been set.

Renewed Regulatory Framework

On December 17, 2010, the OEB initiated a coordinated consultation process for the development of a renewed regulatory framework for electricity distributors and transmitters. On October 18, 2012, the OEB issued its report *A Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, marking the completion of its consultation process. The report identified three rate-setting models available to provide choices suitable for distributors having varying capital requirements: a 4th Generation IRM, which builds on the current 3rd Generation model by adding one year to the IRM period; a Custom IRM, which involves rate setting based on a five-year forecast of a distributor's revenue requirement and sales volume; and an Annual Incentive Rate-setting Index method, which involves annual adjustment of rates by a simple price cap index formula. The report also provided information on performance measurement, continuous improvement and implementation of the new framework.

Four working groups were established to provide expert assistance to review and advise the OEB's staff on proposals regarding certain implementation matters: Asset Redefinition and Regional Infrastructure Planning Process; Distribution Network Investment Planning; Performance, Benchmarking, and Rate Adjustment Indices; and Smart Grid. Hydro One Networks is represented on all four groups. Working group meetings began in November 2012 and are scheduled through February 2013. Consultations will conclude with the issuance of filing requirements and guidance, code amendments, and/or supplemental Board policies in support of the new framework. The OEB is expecting that policies will be largely implemented in time for the 2014 rate year. We are currently assessing the rate-setting methods available.

OEB Transmission and Distribution System Codes

Under the Transmission System Code, the transmitter covers the initial pooling of the costs of enabler lines, with generators paying their pro-rata share when ready to connect, based on generator capacity.

Under the Distribution System Code (DSC), there are three classes of distribution assets associated with the connection of renewable energy generation: connection assets, expansion assets, and renewable enabling improvements. Generators that connect directly to a distributor's system pay the costs of connection assets, while distributors fund: all expansion costs identified in a plan; other generator-requested expansion costs up to a cap of $90,000/MW per project (generator pays the rest); and all renewable enabling improvements.

In 2011, the OEB granted us an exemption from mandatory DSC timelines for the connection of micro-embedded generation facilities. The OEB decision increased the timeline for processing indirect connections that require a site assessment and approved amendments to the conditions that must be met before we are required to connect micro-embedded generation facilities to our distribution system. On August 3, 2012, Hydro One Networks applied to the OEB for an extension of the exemption and on November 8, 2012, the OEB granted the extension for a period ending August 3, 2013, or six months after the conclusion of its consultation on micro-embedded generation issues, whichever is earlier.

Ontario Clean Energy Benefit

Effective January 1, 2011, the Province introduced the *Ontario Clean Energy Benefit Act, 2010*, which is designed to assist Ontario electricity consumers through the transition to a cleaner electricity system. Under this Act, eligible residential, farm and small business consumers receive a 10% benefit with respect to the total cost of electricity on their bills, including tax, for a five-year period. This benefit is applied to customers' electricity costs for each billing period. Effective September 1, 2012, the 10% rebate is applied only to the first 3,000 kWh of electricity consumed per month.

Revenue Decoupling for Distributors

In 2010, the OEB initiated a consultation process to examine the revenue adjustment and cost recovery mechanisms available to electricity and natural gas distributors to address revenue erosion resulting from unforecasted changes in volume of energy sold. These mechanisms are commonly referred to as "revenue decoupling" mechanisms as each involves some means of disconnecting the link between the volume of energy consumed by customers and the recovery by energy distributors of their approved revenue requirement.

On November 26, 2012, the OEB initiated a project to complete the work begun on revenue decoupling for electricity and natural gas distributors. The OEB will coordinate its consideration of revenue decoupling with the new rate-setting policies proposed in the renewed regulatory framework for electricity. The OEB will examine how best to address changes in demand, including potential declines in average use. This consultation will review the options for potential revenue decoupling in addition to the existing lost revenue decoupling mechanism (i.e. the Lost Revenue Adjustment Mechanism or LRAM). The OEB expects to release a draft policy in early 2013. The OEB will solicit stakeholder comments in writing before finalizing the policy.

Distribution Sector Consolidation

On April 13, 2012, the Province announced it was launching a comprehensive review of Ontario's electricity sector to explore options to improve efficiencies, including local distribution companies (LDCs) consolidation. As a result, the Province created the Ontario Distribution Sector Review Panel (Panel). On December 13, 2012, the Panel released its report, *Renewing Ontario's Electricity Distribution Sector: Putting the Consumer First*, with recommendations for electricity sector consolidation. This report recommends that the 73 LDCs comprising the focus of the report be consolidated into eight to 12 larger regional electricity distributors within a two-year timeframe. Specifically, it recommends there be two regional distributors in northern Ontario and between six and ten regional distributors in southern Ontario with a minimum of 400,000 customers each. Given our company's position as the largest LDC, the report recommends that Hydro One Networks be given unambiguous direction to lead and engage in the discussion of the merger of distribution assets with the appropriate interested utilities on a commercial basis. At present, the Province is reviewing the report and assessing the recommendations.

FIT and microFIT

On October 1, 2009, the OPA launched its Feed-in Tariff (FIT) Program which is designed to procure energy from a wide range of renewable energy sources, including wind, solar, photovoltaic, bio-energy and waterpower up to 50 MW.

On March 22, 2012, the Province announced the results of its two-year FIT Program Review, including recommended changes to reflect input received from stakeholders. The OPA implemented these recommendations and re-launched its microFIT program on July 12, 2012. The revised program encourages greater community and aboriginal participation and the protection of agricultural lands. In August 2012, the OPA began to release approvals allowing microFIT projects to proceed. On December 14, 2012, the OPA announced that it will award up to 200 MW of Small FIT applications, received between December 14, 2012 and January 18, 2013, for renewable energy projects with a proposed capacity between ten and 500 kilowatts. The OPA is not accepting Large FIT applications at this time. The timing for the Large FIT project application window will be communicated once details are finalized.

Conservation and Demand Management (CDM)

The OPA continues to be responsible for coordinating the delivery and funding of Ontario's CDM programs. Our CDM programs funded through the OPA in 2012 amounted to approximately $25 million, compared to $15 million in 2011. These programs included: the Peaksaver Program; the Low Income Home Assistance Program; Appliance Retirement and Exchange Events; and the Process and System Upgrade Incentive Program.

The *Ontario Energy Board Act, 1998*, as amended by the GEA, provides direction to the OEB to take steps to establish CDM targets to be met by LDCs and other licencees. A province-wide CDM target for Ontario's LDCs was set in 2010. The two key CDM targets for LDCs over the four-year period beginning January 1, 2011 were to collectively reduce 1,330 MW of provincial summer peak demand and to provide 6,000 GWh of cumulative energy savings. The OEB issued its CDM Code for Electricity Distributors (CDM Code) on September 16, 2010 and on November 12, 2010, it issued final CDM targets to each LDC. Our company was allocated a 259 MW reduction of provincial peak demand and a 1,320 GWh reduction of electricity consumption, representing, respectively, 19.5% and 22.0% of the total target savings established for all LDCs. The CDM Code also set out the conditions and rules that LDCs are required to follow if they choose to use OEB-approved CDM programs to meet their CDM targets.

On April 26, 2012, the OEB issued its CDM guidelines for all electricity distributors. One key change is that savings associated with TOU pricing are eligible to be counted towards the CDM targets. Savings will be evaluated by the OPA for the entire province and then allocated to each distributor. The other key change is the establishment of the LRAM variance account, which captures the variance between the level of CDM included in a distributor's load forecast and the verifiable results of impacts of CDM activities undertaken between 2011 and 2014 for both OPA-contracted and OEB-approved CDM programs.

On September 28, 2012 and September 30, 2012, in accordance with the CDM Code, Hydro One Brampton Networks and Hydro One Networks, respectively, filed their 2011 Annual CDM Reports with the OEB. Our combined results for 2011 were 40 MW in peak demand savings, representing 15.6% of our target, and 99 GWh of annual energy savings. These energy savings will produce 388 GWh towards our target, representing 29.4% of our cumulative target. We anticipate meeting our 2014 cumulative demand and energy savings targets.

On December 21, 2012, the Minister of Energy issued a directive to the OPA to extend funding for its CDM programs for one additional year, to December 31, 2015. This extension aims to provide added stability, support the momentum of province-wide programs and ensure that projects with longer completion times can continue to participate in key conservation initiatives. This extension will also provide an opportunity for the OPA and LDCs to collaboratively work to strengthen the current framework and deliver innovative programs that support Ontario families and businesses. The OPA will be reaching out to distributors to further solicit insight and advice on the implementation of this extension.

Advanced Distribution System

The *Energy Conservation Responsibility Act, 2006* further broadened the objectives of CDM by providing the framework for the installation of smart meters in all homes and small businesses in Ontario. In 2007, the Province appointed the IESO as the interim smart meter entity that would oversee the collection and management of data from installed smart meters. LDCs, including our distribution businesses, are accountable for the deployment of smart meter infrastructure and related communications technology to meet minimum regulatory requirements, as well as the implementation of TOU rates.

In 2011, we carried out a number of studies on advanced distribution technologies and initiated the Smart Zone Pilot Project in the Owen Sound area. The Smart Zone Pilot consists of testing and demonstrating power system equipment, IT systems and communication systems that will be required to help facilitate the connection of a large number of Distributed Generation (DG) connections to our distribution system. In 2012, we successfully completed the deployment of the Distribution Management System (DMS) within the Owen Sound pilot area. This integrates the Network Management System, the Outage Response Management System and field devices. Further releases of the ADS will look at optimizing outage response through more effective dispatch, automation to isolate faults where needed and the dynamic regulation of voltage to reduce losses. All releases leverage a core infrastructure and build on each other, and as pilot elements are proven, business cases will be developed for the provincial roll out which will ultimately comprise the ADS.

RESULTS OF OPERATIONS

Revenues

Year ended December 31 (millions of dollars)	2012	2011	$ Change	% Change
Transmission	1,482	1,389	93	7
Distribution	4,184	4,019	165	4
Other	62	63	(1)	(2)
	5,728	5,471	257	5
Average annual Ontario 60-minute peak demand *(MW)*[1]	21,132	21,166	(34)	-
Distribution – units distributed to customers *(TWh)*[1]	29.2	29.2	-	-

[1] System-related statistics are preliminary.

Transmission

Transmission revenues primarily consist of our transmission tariff, which is based on the monthly peak electricity demand across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand. Demand is primarily influenced by weather and economic conditions. Transmission revenues also include export revenues associated with transmitting excess generation to surrounding markets and ancillary revenues which are mostly attributable to maintenance services provided primarily to generators and secondary use of our land rights.

Our transmission revenues were higher by $93 million, or 7%, compared to 2011. On December 23, 2010, the OEB rendered its decision on our 2011 and 2012 transmission rate application. On December 20, 2011, the OEB approved new transmission tariff rates, effective January 1, 2012, which reflected higher in-service assets and the use of US GAAP as our basis for rate setting. The decisions resulted in higher transmission revenues of $106 million for the year ended December 31, 2012, and the average peak demand for 2012 resulted in a slight increase of $3 million, compared to the prior year.

Increases were partially offset by a $9 million reduction in revenue following the completion of recovery of a transmission regulatory account effective December 31, 2011, a $6 million reduction in transmission-related external revenues and a $1 million reduction associated with other OEB-approved regulatory accounts.

Distribution

Our consolidated Distribution Business consists of the separate distribution businesses of our subsidiaries Hydro One Networks, Hydro One Brampton Networks, and Hydro One Remote Communities. Distribution revenues include our distribution tariff and amounts to recover the cost of purchased power used by the customers of our consolidated Distribution Business. Accordingly, our distribution revenues are influenced by the amount of electricity we distribute, the cost of purchased power and our distribution tariff rates. Distribution revenues also include minor ancillary distribution services revenues, such as fees related to the joint use of our distribution poles by the telecommunications and cable television industries as well as miscellaneous charges, such as those for late payments.

Our 2012 distribution revenues were higher by $165 million, or 4%, compared to 2011. The increase was primarily due to the recovery of higher purchased power costs of $146 million, as described below under "Purchased Power." Our distribution revenues were also higher by $18 million due to our placement of new ADS and smart meter investments in service. Given that these investments relate to new technologies, they are currently recovered through separate rate mechanisms.

Distribution revenues for the year reflect additional external revenues of $7 million, an increase in Hydro One Remote Communities' revenues of $2 million and a $1 million increase associated with OEB-approved regulatory accounts. These increases were partially offset by a $7 million reduction due to lower energy consumption, resulting primarily from the milder winter we experienced in 2012 compared to 2011, and by a decrease of $2 million in Hydro One Brampton Networks' distribution tariff revenues.

Purchased Power

Purchased power costs are incurred by our Distribution Business and represent the cost of electricity delivered to customers within our distribution service territories. These costs comprise the wholesale commodity cost of energy, the IESO's wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy for certain low-volume and designated customers is based on the OEB's RPP, which consists of a two-tiered pricing structure with threshold amounts and a separate pricing structure for RPP customers on TOU billing, both of which are adjusted twice annually. We began transitioning our RPP customers to TOU billing in May 2010, and a large majority of our RPP customers are now on TOU billing. Customers who are not eligible for the RPP pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*.

A summary of the RPP for the reporting and comparative periods is provided below.

RPP	Tier Threshold (kWh/month)		Tier Rates (cents/kWh)	
Effective Date	**Residential**	**Non-Residential**	**First Tier**	**Second Tier**
November 1, 2010	1,000	750	6.4	7.4
May 1, 2011	600	750	6.8	7.9
November 1, 2011	1,000	750	7.1	8.3
May 1, 2012	600	750	7.5	8.8
November 1, 2012	1,000	750	7.4	8.7

RPP TOU	Rates (cents/kWh)		
Effective Date	**On Peak**	**Mid Peak**	**Off Peak**
November 1, 2010	9.9	8.1	5.1
May 1, 2011	10.7	8.9	5.9
November 1, 2011	10.8	9.2	6.2
May 1, 2012	11.7	10.0	6.5
November 1, 2012	11.8	9.9	6.3

Purchased power costs increased by $146 million, or 6%, to $2,774 million for the year, compared to 2011. The increase in our purchased power costs was primarily due to an increase of $118 million resulting from the impact of changes in the OEB's RPP rates for residential and other eligible customers, a $33 million increase resulting from the OEB transmission rate decision effective January 1, 2012 that affected the transmission charges levied by the IESO, and a $7 million increase related to higher electricity demand. The effect of these increases was partially offset by an $11 million reduction compared to 2011 in wholesale market service charges levied by the IESO, which include certain costs for operating the transmission grid, and a $1 million decrease resulting from lower purchased power costs for customers who are not eligible for the RPP.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs consist of labour, material, equipment and purchased services which support the operation and maintenance of the transmission and distribution systems. Also included in these costs are property taxes and payments in lieu thereof related to certain of our transmission and distribution facilities.

Operation, maintenance and administration costs for each of our three business segments were as follows:

Year ended December 31 (millions of dollars)	2012	2011	$ Change	% Change
Transmission	402	422	(20)	(5)
Distribution	608	609	(1)	-
Other	61	61	-	-
	1,071	1,092	(21)	(2)

Our company continues to focus on managing its costs, resulting in a decrease in total operation, maintenance and administration expenditures in 2012, compared to 2011, while continuing to substantially complete the planned work programs for both our transmission and distribution businesses.

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way decreased by $20 million, or 5%, in 2012 compared to last year. Within our work programs, we continued to invest in the safe and reliable operation of our transmission system that spans Ontario. Our work program requirements were lower by $33 million compared to last year mainly due to: lower demand for station-related corrective maintenance, particularly for power equipment; lower demand for underground cable corrective maintenance; and reduced autotransformer remediation work. We also incurred lower expenditures compared to last year related to the OPA's recommendation to increase short circuit and/or transformer capacity at a number of our transmission stations to enable the connection of small renewable projects, for which recovery is restricted (see "Regulation – Long-Term Energy Plan"). Most of this work has now been completed. Expenditures in support of our transmission system increased by $13 million, compared to 2011, due to a redirection of resources from our Distribution Business, partially offset by management cost reduction initiatives.

Distribution

Operation, maintenance and administration expenditures required to maintain our low-voltage distribution system decreased slightly by $1 million compared to last year. Our work program expenditures decreased by $5 million mainly due to decreased power restoration expenditures resulting from overall lower storm activity in Ontario in 2012 compared to 2011. Reductions also resulted from lower lines maintenance requirements, partially offset by increased requirements within our forestry program resulting from higher tree densities experienced this year. Our expenditures in support of our distribution system increased by $4 million mainly due to spending in support of the Customer Information System (CIS) phase of our entity-wide information system replacement and improvement project. The impact of this increase was partially offset by cost reduction initiatives and a redirection of resources in support of our Transmission Business.

Depreciation and Amortization

Depreciation and amortization expense increased by $43 million, or 7%, in 2012, compared to 2011. This increase was attributable to higher depreciation expense of $40 million, when compared to 2011, primarily related to our placement of new assets in service consistent with our ongoing capital work program. Slightly higher asset removal costs of $3 million contributed the remainder of the variance from the prior year.

Financing Charges

Financing charges increased by $14 million, or 4%, to $358 million for 2012 compared to 2011. Higher financing costs were mainly due to an increased average level of debt and partially offset by a lower average effective interest rate.

Provision for Payments in Lieu of Corporate Income Taxes (PILs)

The provision for PILs decreased by $29 million, or 19%, to $121 million in 2012, compared to 2011. This decrease primarily resulted from a reduction in the statutory tax rate from 28.25% to 26.50%, changes in net temporary differences, and an increase in research and development tax credits related to our ADS project. This reduction was partially offset by the impact of higher levels of pre-tax income compared to 2011.

Net Income

Net income of $745 million was higher by $104 million, or 16%, than our comparable 2011 results. Higher revenues reflect the recovery of prior year investments which are now in service and which will improve the province's electricity system. Our net income was also positively impacted by lower operation, maintenance and administration expenditures resulting from cost-effectively managing the work program within our Transmission Business and by lower PILs resulting from a lower combined federal and provincial statutory income tax rate compared to 2011. In addition, our 2012 net income reflects higher depreciation expense resulting from our placement of new assets in service, consistent with our increased capital work program, and increased financing charges reflecting our higher average level of debt.

QUARTERLY RESULTS OF OPERATIONS

The following table sets forth unaudited quarterly information for each of the eight quarters, from the quarter ended March 31, 2011 through December 31, 2012. This information has been derived from our unaudited interim Consolidated Financial Statements and our audited annual Consolidated Financial Statements which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(millions of dollars)	2012				2011			
Quarter ended	**Dec. 31**	**Sept. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sept. 30**	**Jun. 30**	**Mar. 31**
Total revenue	1,435	1,466	1,359	1,468	1,359	1,384	1,268	1,460
Net income	165	201	169	210	120	167	142	212
Net income to common shareholder	160	197	164	206	115	163	137	208

Electricity demand generally follows normal weather-related variations, and consequently, our electricity-related revenues and profit, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of liquidity and capital resources are funds generated from our operations, debt capital market borrowings and bank financing. These resources will be used to satisfy our capital resource requirements, which continue to include our capital expenditures, servicing and repayment of our debt, and dividends.

Summary of Sources and Uses of Cash

Year ended December 31 (millions of dollars)	**2012**	**2011**
Operating activities	1,285	1,407
Financing activities		
Long-term debt issued	1,085	700
Long-term debt retired	(600)	(500)
Dividends paid	(370)	(168)
Investing activities		
Capital expenditures	(1,454)	(1,447)
Other financing and investing activities	21	64
Net change in cash and cash equivalents	(33)	56

Operating Activities

Net cash from operating activities decreased by $122 million to $1,285 million in 2012, compared to 2011. The decrease was primarily due to changes in accrued liabilities related to customer prepayments, and a reduction in taxes payable, resulting from a tax payment made in the first quarter of 2012 related to the 2011 taxation year, as well as the timing of tax installment payments in 2012, compared to 2011. The decrease was partly offset by higher 2012 net income, compared to 2011.

Financing Activities

Short-term liquidity is provided through funds from operations, our Commercial Paper Program, under which we are authorized to issue up to $1,000 million in short-term notes with a term to maturity of less than 365 days, our revolving credit facility, and through our holding of Province of Ontario Floating-Rate Notes.

Our Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities comprised of our $1,250 million committed revolving credit facility with a syndicate of banks, which matures in June 2017, and a long-term investment in Province of Ontario Floating-Rate Notes of $250 million (with a fair value of $251 million at December 31, 2012). The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements.

At December 31, 2012, we had $8,460 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2013 and 2062. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note (MTN) Program. The maximum authorized principal amount of medium-term notes issuable under this program is $3,000 million. At December 31, 2012, $1,515 million remained available until September 2013.

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.[1]	Prime-1	A1
Standard & Poor's (S&P)[2]	A-1	A+

[1] On April 27, 2012, Moody's Investors Service Inc. downgraded our senior unsecured rating to A1 from Aa3.
[2] On April 25, 2012, S&P revised their outlook on our company to negative from stable.

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets, and impose a negative pledge provision, subject to customary exceptions. The credit agreements related to our credit facilities have no material adverse change clauses that could trigger default. However, the credit agreements require that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreements also provide limitations that debt cannot exceed 75% of total capitalization and that third-party debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We were in compliance with all these covenants and limitations at December 31, 2012.

In 2012, we successfully issued $1,085 million in cost-effective long-term debt under our MTN Program, consisting of $300 million issued in the first quarter, $425 million issued in the second quarter, $310 million issued in the third quarter, and $50 million issued in the fourth quarter of 2012. In the third quarter of 2012, we also called and redeemed $600 million of our long-term debt, prior to its maturity date of November 15, 2012.

In 2011, we issued $700 million in long-term debt under our MTN Program, consisting of $300 million issued in the first quarter, $300 million issued in the third quarter, and $100 million issued in the fourth quarter of 2011. In 2011, we also repaid $500 million in maturing long-term debt, $250 million in the first quarter and $250 million in the fourth quarter.

We had no short-term notes outstanding as at December 31, 2012 or December 31, 2011.

Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, maintenance of the deemed regulatory capital structure, financial condition, cash requirements, and other relevant factors such as industry practice and shareholder expectations. Common dividends pertaining to our quarterly financial results are generally declared and paid in the immediately following quarter.

In 2012, we paid dividends to the Province in the amount of $370 million, consisting of $352 million in common dividends and $18 million in preferred dividends. In 2011, we paid dividends in the amount of $168 million, consisting of $150 million in common dividends and $18 million in preferred dividends.

In 2012, cash dividends per common share were $3,523, compared to $1,500 per common share in 2011. Cash dividends per preferred share were $1,375 in each of 2012 and 2011.

Our objectives with respect to our capital structure are to maintain effective access to capital on a long-term basis at reasonable rates and to deliver appropriate financial returns to our shareholder.

Investing Activities

Cash used for investing activities, primarily representing capital expenditures to enhance and reinforce our transmission and distribution infrastructure in the public interest, was as follows:

Year ended December 31 (millions of dollars)	**2012**	**2011**	**$ Change**	**% Change**
Transmission	776	810	(34)	(4)
Distribution	671	628	43	7
Other	7	9	(2)	(22)
	1,454	1,447	7	-

Transmission

Transmission capital expenditures decreased by $34 million, or 4%, to $776 million in 2012, compared to 2011. Investments to expand and reinforce our transmission system were $313 million, representing a decrease of $103 million from last year. The majority of our expenditures were made on inter-area network projects to support the Province's supply mix objectives for generation, although we continue to make significant investments in load customer connection and local area supply projects to address growing loads. The 2012 decrease in our expenditures results from the completion of several large projects in 2011. Major inter-area network projects completed and put into service in 2011 included the installation of SVCs at our Nanticoke, Detweiler, Porcupine and Kirkland Lake transformer stations. Also contributing to the reduction in expenditures were lower expenditures in 2012 related to our Woodstock Area Transmission Reinforcement Project to increase capacity and ensure supply reliability in the Woodstock area, and our Bruce to Milton Transmission Reinforcement Project connecting refurbished nuclear and new wind generation sources in the Huron-Grey-Bruce area. These projects were successfully put into service in March and May of this year, respectively. The impact of the reductions in expenditures in both periods was partially offset by increases in our expenditures resulting from load customer connection and local area supply projects progressing into their build phases, and investments in our transformer stations related to the ADS Project, which supports clean DG connected to our distribution system consistent with the GEA.

On June 18, 2012, our subsidiary Hydro One Networks entered into an agreement with the Chippewas of Nawash First Nation and the Chippewas of Saugeen First Nation, collectively known as the Saugeen Ojibway Nation (SON). The agreement contemplates a new Limited Partnership (LP) to hold only the lines and related land rights of our Bruce to Milton Transmission Reinforcement Project. The carrying value of these assets is expected to be approximately $600 million when they are transferred to the LP in late 2013. Under the terms of our agreement, the SON will be eligible to purchase a non-controlling equity interest in the LP at fair value. The LP is anticipated to become a rate-regulated entity under the jurisdiction of the OEB. Transfer of our assets to the LP and subsequent sale of an equity interest to the SON are both subject to the receipt of future regulatory approvals from the OEB. On December 18, 2012, the SON, Hydro One Networks and Hydro One signed a Letter Agreement in connection with the establishment of the LP. The Letter Agreement addresses, among other things, the terms of the LP Agreement to be entered into on closing and the terms on which Hydro One Networks will operate the Bruce to Milton Line on behalf of the LP. The closing is conditional on certain regulatory approvals and tax rulings.

Our local area supply project expenditures include investments in our Switchyard Reconstruction Project at our Burlington Transformer Station, which will address aging infrastructure to increase the load supply capacity and to ensure reliability of supply to customers in the area. The project successfully went into service on December 21, 2012. We continue to invest in our Midtown Electricity Infrastructure Renewal Project to replace aging cable and overhead line facilities and to provide additional supply capability to meet future load growth in midtown Toronto as well as areas to the west. Work is progressing at our Hearn Switching Station to rebuild an existing switchyard that has reached its end-of-life. This project will also increase short circuit capability to accommodate future connection of renewable generation in central and downtown Toronto.

Significant expenditures within our load customer connection projects include investments to build our Commerce Way Transformer Station, a new load supply station in the City of Woodstock that was partially put into service on December 19, 2012. This project will provide additional transformation and line capacity to address load growth issues in the Woodstock area.

Expenditures to sustain our existing transmission system were $392 million in 2012, representing an increase of $57 million compared to 2011. During the year, we made significant investments in the refurbishment and replacement of end-of-life equipment, including end-of-life oil circuit breakers, switches, insulators and protections at our Abitibi Canyon switching station, and deteriorated autotransformers at our Trafalgar and Claireville transformer stations. Of these projects, the autotransformer at our Trafalgar transformer station and one of two at our Claireville transformer station were successfully put into service this year. During the year, we also experienced an increase in replacements for end-of-life protection and control equipment.

Our other transmission capital expenditures were $71 million in 2012, representing an increase of $12 million compared to 2011. The majority of these increased expenditures were related to fleet acquisitions and to information technology (IT) investments.

Distribution

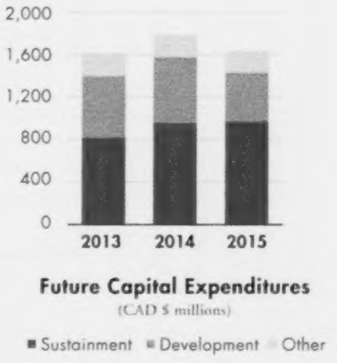
Our distribution capital expenditures increased by $43 million, or 7%, to $671 million in 2012, compared to 2011. Capital investments to expand and reinforce our distribution network were $284 million in 2012, representing an increase of $15 million compared to 2011. We experienced increases in 2012 related to our continued investments in our ADS Project, a multi-year initiative to identify, deploy, analyze and assess equipment and applications to modernize our distribution system. The ADS Project will protect distributed generators from power interruption and is anticipated to improve outage restoration, reduce construction and ongoing maintenance costs, and reduce power loss as it flows across the electricity grid. Increased capital expenditures in 2012 were also due to investments related to our other distribution projects and upgrades to safely and reliably accommodate additional renewable energy, and to higher volumes of new customer connections and upgrades, partially offset by reduced expenditures within our Smart Meter Project as it nears completion.

Expenditures to sustain our distribution system network were $245 million in 2012, representing an increase of $5 million compared to 2011. The increase in our sustainment program was primarily impacted by increased work accomplished within our lines and distribution station refurbishment programs, as well as higher expenditures related to the strategic purchase of power transformers compared to the prior year. These impacts were partially offset by lower storm restoration work given lower storm activity in 2012 compared to two major storms in Ontario in 2011.

Other distribution capital expenditures were $142 million in 2012, representing an increase of $23 million, compared to 2011. The majority of these expenditures were related to the CIS phase of our enterprise-wide information system replacement and improvement project. In addition to replacing end-of-life systems, this implementation will result in process improvements that are expected to provide many benefits, including enhancements to customer satisfaction through reduced call times and first call resolution of issues given faster availability of information. Productivity savings are anticipated to result from performance improvements, consolidation of systems, and decommissioning of over a dozen legacy systems.

Future Capital Expenditures

Our capital expenditures for 2013 are budgeted at approximately $1,600 million. Our 2013 capital budgets for our transmission and distribution businesses are about $1,000 million and $600 million, respectively. Consolidated capital expenditures are expected to be approximately $1,750 million in 2014 and $1,650 million in 2015. These expenditure levels reflect meeting the sustainment requirements of our aging infrastructure. Our sustainment program is expected to be approximately $800 million in 2013, $950 million in 2014 and $1,000 million in 2015. Our development projects include the ADS, inter-area network upgrades that reflect supply mix policies, local area supply requirements, and requirements to enable DG. Our development expenditures are expected to be approximately $600 million in 2013, $600 million in 2014, and $450 million in 2015. These development investments also reflect customer demand work. Other capital expenditures are expected to be approximately $200 million in each of 2013, 2014 and 2015. These expenditures include investments to replace our end-of-life customer billing system and smaller projects related to the continued realization of increased productivity from our enterprise-wide SAP information system.



Future Capital Expenditures
(CAD $ millions)

Transmission

Transmission capital expenditures include significant investments to manage the replacement and refurbishment of our aging transmission infrastructure in order to ensure a continued reliable supply of energy to customers throughout the province. Our investment plan includes sustainment investments to replace end-of-life air blast circuit breakers and switchgear, high-voltage underground cable, and aging power transformers and to comply with North American Electricity Reliability Corporation cyber security requirements. These sustaining investments are necessary to ensure that we continue to meet all regulatory, compliance, safety and environmental objectives.

Major capital investments include our Oshawa Area Transformer Station Project to install additional auto-transformer capacity at our proposed Clarington Transformer Station, for which the OPA has requested that Hydro One develop an implementation plan and initiate work. Planning and environmental studies are currently being undertaken for this project. Investments also include our Midtown Electricity Infrastructure Renewal Project that will provide additional supply capability to meet future load growth in midtown Toronto as well as areas to the west, our SVC installation to be completed at our Milton station, and our project to rebuild the switching station at our Hearn Transformer Station, which is expected to be completed by 2014. Transmission investments for ADS and requirements to enable DG are also included in the investment plan. The Hearn Transformer Station Project, when combined with four other transformer station upgrades, will collectively enable up to 600 MW of new transmission capacity.

On December 22, 2010, we received a letter from the Minister of Energy requesting us to proceed with the necessary planning and development work for specified transmission projects and upgrades to safely and reliably accommodate additional renewable energy. On April 7, 2011, the OPA provided the scope and timing to increase short circuit and/or transformer capacity at ten of 15 transformer stations. These upgrades are substantially complete. Expenditures for these upgrades have been recorded within operation, maintenance and administration (see "Regulation – Long-Term Energy Plan"). Two of the three priority specified transmission projects are reflected in our budgeted capital expenditures. The West of London Transmission Upgrade Project generally requires restringing conductor on existing towers along an existing right-of-way and will enable the connection of additional renewable generation in the west of London area. The Southwestern Ontario Reactive Compensation Priority Project will increase the transmission capability of the Bruce transmission system. We are awaiting direction on the third priority project from the OPA (see "Regulation – Long-Term Energy Plan").

In August 2010, the OEB introduced a framework for competitive designation for the development of eligible transmission projects. As a result, we did not include in our budgeted capital expenditures any projects that could meet the definition of expansions under the OEB's competitive framework. We do not plan to undertake large capital expenditures without a reasonable expectation of recovering them in our rates.

The actual timing and expenditures of many development projects are uncertain as they are dependent upon: various approvals including OEB leave to construct approvals and environmental assessment approvals; negotiations with customers, neighbouring utilities and other stakeholders; and consultations with First Nations and Métis communities. Projects are also dependent on the timing and level of generator contributions for enabling facilities.

Distribution

Distribution capital expenditures include investments to support the sustainment of our capital infrastructure. Our core work will continue to focus on the performance of our aging distribution asset base in order to improve system reliability. There are continuing investments to replace end-of-life equipment and components, implement ADS as part of this renewal and a focus on wood pole replacements to maintain reliability. In addition, we will continue to address customer demand projects through connectivity for DG, the demand for new load connections, trouble calls, storm restoration and system capability reinforcement.

Distribution development expenditures over the period are primarily related to the development of an ADS system and related grid modernization standards, customer demand work such as connections and upgrades, work to facilitate DG connections, including station upgrades, protection and control, new lines and some contestable work for which we receive capital contributions. During the 2013 and 2014 periods, we expect to manage a significant number of projects throughout the province to address load growth and the stress on our system components.

DG expenditures are based on our estimate of the number of anticipated connections, which have been reduced based on the experience gained since 2009 and changes that have occurred to the FIT Program. The budget only reflects expenditures for projects with FIT and microFIT Program contracts from the OPA that are expected to connect to our distribution system.

In 2013, the ADS Project will look at optimizing outage response through more effective dispatch, automation to isolate faults where needed and the dynamic regulation of voltage to reduce losses.

Summary of Contractual Obligations and Other Commercial Commitments

There are no off-balance-sheet arrangements that have, or are reasonably likely to have, a material current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

The following table presents a summary of our debt and other major contractual obligations, as well as other major commercial commitments.

December 31, 2012 (millions of dollars)	Total	2013	2014/2015	2016/2017	After 2017
Contractual Obligations *(due by year)*					
Long-term debt – principal repayments	8,460	600	1,300	1,100	5,460
Long-term debt – interest payments	7,336	410	735	651	5,540
Pension[1]	330	158	172	-	-
Environmental and asset retirement obligations[2]	313	30	73	40	170
Inergi LP (Inergi) outsourcing agreement[3]	287	136	151	-	-
Operating lease commitments	53	10	15	14	14
Total Contractual Obligations[4]	16,779	1,344	2,446	1,805	11,184
Other Commercial Commitments *(by year of expiry)*					
Bank line[5]	1,250	-	-	1,250	-
Letters of credit[6]	150	150	-	-	-
Guarantees[6]	326	326	-	-	-
Total Other Commercial Commitments	1,726	476	-	1,250	-

[1] Contributions to the Hydro One Pension Fund are generally made one month in arrears. The 2013 and 2014 minimum contributions are based on an actuarial valuation filed in May 2012 and effective December 31, 2011. Based on expected levels of 2012 pensionable earnings, our total 2012 annual pension contributions were approximately $160 million. Future minimum contributions beyond 2014 will be based on an actuarial valuation effective no later than December 31, 2014, and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension contributions beyond 2014 are not estimable at this time.

[2] We record a liability for the estimated future expenditures associated with the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated insulating oil from electrical equipment and for the assessment and remediation of contaminated lands, as well as asset retirement obligations for the removal of asbestos-contaminated materials from our facilities and the decommissioning and removal of certain switching stations. The expenditure pattern reflects our planned work programs for the periods.

[3] On March 1, 2002, Inergi began providing a range of services to us for a ten-year period, including IT, customer care, supply chain and certain human resources and finance services. On May 1, 2010, consistent with the terms of the contract, our company extended the Master Services Agreement with Inergi for a further three-year period, to expire on February 28, 2015. Given the complexities involved, we have begun developing a plan of action for end-of-term and anticipate working towards a request for proposal in 2013. The amounts disclosed include an estimated annual inflation adjustment in the range of 1.8% to 3.0%.

[4] In addition, our company has entered into various agreements to purchase goods or services in support of our work programs that are enforceable and legally binding. None of these agreements is considered individually material, and the majority do not extend beyond December 31, 2013.

[5] In support of our liquidity requirements, we have a $1,250 million revolving standby credit facility with a syndicate of banks that matures in June 2017.

[6] We currently have outstanding bank letters of credit of $127 million relating to retirement compensation arrangements. On April 27, 2012, our highest credit rating declined from the "Aa" category to the "A" category. Based on this credit rating category, we began providing prudential support to the IESO in the form of letters of credit, the amount of which is calculated based on forecasted monthly power consumption. As at December 31, 2012, we provided letters of credit to the IESO in the amount of $22 million to meet our current prudential requirement. The other $1 million pertains to operating letters of credit. We have also provided prudential support to the IESO on behalf of our subsidiaries as required by the IESO's Market Rules, using parental guarantees of up to a maximum of $325 million, and on behalf of two distributors using guarantees of up to a maximum of $0.7 million.

The amounts in the above table under long-term debt – principal repayments are not charged to our results of operations, but are reflected on our Consolidated Balance Sheets and Consolidated Statements of Cash Flows. Interest associated with this debt is recorded under financing charges on our Consolidated Statements of Operations and Comprehensive Income or as a cost of our capital programs. Payments in respect of operating leases and our outsourcing agreement with Inergi are recorded under operation, maintenance and administration expense on our Consolidated Statements of Operations and Comprehensive Income or as a cost of our capital programs.

RELATED PARTY TRANSACTIONS

Related party transactions primarily consist of our transmission revenues received from, and our power purchase payments made to the IESO, which is a related party by virtue of its status as an agency of the Province. The year-over-year changes related to these amounts are described more fully in the discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends, which are paid to the Province, and our PILs and some of our property taxes, which are paid or payable to the OEFC. In January 2010, we purchased $250 million of Province of Ontario Floating-Rate Notes, maturing on November 19, 2014, as a form of alternate liquidity to supplement our bank credit facilities.

CONSIDERATIONS OF CURRENT ECONOMIC CONDITIONS

Effect of Load on Revenue

Our load, based on normal weather patterns, is expected to marginally decline in 2013 due to the impact of CDM and embedded generation, partially offset by load growth associated with economic growth in all sectors of the Ontario economy. Overall load growth due to the economy alone is forecasted to be approximately 1.3%, with the commercial and industrial sectors slightly outperforming the residential sector. The load impacts of CDM and embedded generation are expected to have a negative impact on load growth of approximately 1.1% and 0.3%, respectively. On the whole, our load is expected to decline by about 0.1% in 2013. Our approved revenue requirement for 2013 has taken the expected load decline into account. A reduction in load, beyond our load forecast included in our approved revenue requirement, would negatively impact our financial results.

Effect of Interest Rates

Changes in interest rates will impact the calculation of the revenue requirements upon which our rates are based. The first component impacted by interest rates is our ROE. The OEB-approved adjustment formula for calculating ROE will increase or decrease by 50% of the change between the current Long Canada Bond Forecast and the risk-free rate established at 4.25% and 50% of the change in the spread in 30-year "A"-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield established at 1.415%. All other things being equal, we estimate that a 1% decrease in the forecasted long-term Government of Canada bond yield used in determining our ROE would reduce Hydro One Networks' transmission and distribution businesses' results of operations by approximately $19 million and $10 million, respectively. As interest rates decline, there is more risk of a decline in our net income. The second component of revenue requirement that would be impacted by interest rates is the return on debt. The difference between actual interest rates on new debt issuances and those approved for return by the OEB would impact our results of operations.

Input Costs and Commodity Pricing

In support of our ongoing work programs, we are required to procure materials, supplies and services. To manage our total costs, we regularly establish security of supply, strategic material and services contracts, general outline agreements, and vendor alliances and we also manage a stock of commonly used items. Such arrangements are for a defined period of time and are monitored. Where advantageous, we develop long-term contractual relationships with suppliers to optimize the cost of goods and services and to ensure the availability and timely supply of critical items. As a result of our strategic sourcing practices, we do not foresee any adverse impacts on our business from current economic conditions in respect of adequacy and timing of supply and credit risk of our counterparties. Further, we have been able to realize significant savings through our strategic sourcing initiatives.

Debt Financing

Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund capital expenditures or meet debt maturity repayments and other liquidity requirements (see "Risk Management and Risk Factors – Risk Associated with Arranging Debt Financing"). We rely on debt financing through our MTN Program and Commercial Paper Program. Our Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities as at December 31, 2012, which is comprised of a $1,250 million syndicated bank line of credit and the holding of $250 million of Province of Ontario Floating-Rate Notes. In 2012, we continued issuing sufficient cost-effective debt financing through the MTN Program in the Canadian capital markets and we arranged sufficient available liquidity. Economic conditions were challenging in 2012 and we expect they will remain challenging in 2013.

Pension

In 2012, we contributed approximately $160 million to our pension plan and incurred $207 million in net periodic pension benefit cost. An actuarial valuation filed in May 2012 and effective December 31, 2011 did not result in significant changes to our 2012 required contributions or our 2012 net periodic benefit cost. Actuarial valuations are minimally required to be filed every three years. We currently estimate our total annual pension contributions to be approximately $160 million for 2013 and 2014, based on the projected level of pensionable earnings and the same actuarial valuation effective December 31, 2011. Future minimum contributions beyond 2014 will be based on the actuarial valuation effective no later than December 31, 2014. Our pension plan experienced positive returns of about 9.19% in 2012. Our pension obligation is impacted by interest rates. The 1% decrease in the discount rate, from 5.25% at December 31, 2011 to 4.25% at December 31, 2012, resulted in an increase in the pension obligation of $862 million and an increase to our post-retirement and post-employment benefit obligation of $241 million. No new benefits were introduced and over the last number of years benefits have been reduced through re-negotiations with certain of our unions as well as our management employees.

RISK MANAGEMENT AND RISK FACTORS

We have an Enterprise Risk Management (ERM) Program that aims at balancing business risks and returns. An enterprise-wide approach enables regulatory, strategic, operational and financial risks to be managed and aligned with our strategic goals. Our ERM program helps us to better understand uncertainty and its potential impact on our strategic goals. It sets out the uniform principles, processes and criteria for identifying, assessing, evaluating, treating, monitoring and communicating risks across all lines of business. It supports our Board of Directors' corporate governance needs and the due diligence responsibilities of senior management.

While our philosophy is that risk management is the responsibility of all employees, the Board of Directors annually reviews our company's risk tolerances, risk management policies, processes and accountabilities. Twice per year, the Board of Directors reviews our risk profile, which is the list of key risks prepared by senior management, that represents the greatest threats to meeting our strategic objectives. The Audit and Finance Committee of our Board of Directors annually reviews the status of our internal control framework.

Our President and Chief Executive Officer (CEO) has ultimate accountability for risk management. Our Leadership Team provides senior management oversight of our risk portfolio and our risk management processes. The leadership team provides direction on the evolution of these processes and identifies priority areas of focus for risk assessment and mitigation planning.

Our Chief Administration Officer and Chief Financial Officer (CAO and CFO) is responsible for ensuring that the risk management program is an integral part of our business strategy, planning and objective setting. The CAO and CFO has specific accountability for ensuring that enterprise risk management processes are established, properly documented and maintained by our company.

Our senior managers, line and functional managers are responsible for managing risks within the scope of their authority and accountability. Risk acceptance or mitigation decisions are made within the risk tolerances specified by the head of the subsidiary or function.

The CAO and CFO provides support to the Audit and Finance Committee of our Board of Directors, the President and CEO, the senior management team and key managers within our company. This support includes developing risk management frameworks, policies and processes, introducing and promoting new techniques, establishing risk tolerances, preparing annual corporate risk profiles, maintaining a registry of key business risks and facilitating risk assessments across our company. Our internal audit staff is responsible for performing independent reviews of the effectiveness of risk management policies, processes and systems. Starting in 2013, our Board of Directors has taken on an enhanced role in our governance structure. Each committee of the Board of Directors will take accountability for reviewing specific risks of our company.

Key elements of our ERM Program enable us to identify, assess and monitor our risks effectively. These include having an ERM policy and framework which communicates our philosophy and process for risk management across our company. A discussion of risks is an integral part of each line of business' planning documents on an annual basis. Risk identification is also considered as part of each business case for investments. Finally, discrete risk assessments and workshops are performed for specific lines of business, key projects and various profiles, such as customer relationships and regulatory compliance.
In order to drive consistency throughout our risk identification and risk management processes, we use a standard list of risk sources known as our risk universe. These sources are maintained in a single database that provides a consistent basis for risk identification and classification and serves as a repository for our risk assessments. All risk assessments in our company start with this risk universe. We also use standard risk criteria, which establish the metrics and terminology used for assessing and communicating on risks, and help ensure a consistent basis for our risk assessments and risk evaluations across all lines of business. Risk criteria include formally established risk tolerances and standard scales for assessing the probability of a risk materializing and the strength of controls in place to mitigate them.

Ownership by the Province

The Province owns all of our outstanding shares. Accordingly, the Province has the power to determine the composition of our Board of Directors and appoint the Chair, and influence our major business and corporate decisions. We and the Province have entered into a memorandum of agreement relating to certain aspects of the governance of our company. Pursuant to such agreement, in September 2008, the Province made a declaration removing certain powers from our company's Directors pertaining to the off-shoring of jobs under the outsourcing arrangement with Inergi. In 2009, the Province required our company, among other entities, to adhere to certain accountability measures regarding consulting contracts and employee travel, meal and hospitality expenses. The Province may require us to adhere to further accountability measures or may make similar declarations in the future, some of which may have a material adverse effect on our business. Our credit ratings may change with the credit ratings of the Province, to the extent the credit rating agencies link the two ratings by virtue of Hydro One's ownership by the Province.

Conflicts of interest may arise between us and the Province as a result of the obligation of the Province to act in the best interests of the residents of Ontario in a broad range of matters, including the regulation of Ontario's electricity industry and environmental matters, any future sale or other transaction by the Province with respect to its ownership interest in our company, including any potential outcomes arising out of the recommendations of the Ontario Distribution Sector Review Panel's report, the Province's ownership of Ontario Power Generation Inc., and the determination of the amount of dividend or proxy tax payments. We may not be able to resolve any potential conflict with the Province on terms satisfactory to us which could have a material adverse effect on our business.

Regulatory Risk

We are subject to regulatory risks, including the approval by the OEB of rates for our transmission and distribution businesses that permit a reasonable opportunity to recover the estimated costs of providing safe and reliable service on a timely basis and earn the approved rates of return.

The OEB approves our transmission and distribution rates based on projected electricity load and consumption levels. If actual load or consumption materially falls below projected levels, our net income for either, or both, of these businesses could be materially adversely affected. Also, our current revenue requirements for these businesses are based on cost assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in our costs.

Our load could also be negatively affected by successful CDM programs. We are also subject to risk of revenue loss from other factors, such as economic trends and weather.

We expect to make investments in the coming years to connect new renewable generating stations. There is the possibility that we could incur unexpected capital expenditures to maintain or improve our assets, particularly given that new technology is required to support renewable generation and unforeseen technical issues may be identified through implementation of projects. The risk exists that the OEB may not allow full recovery of such investments in the future. To the extent possible, we aim to mitigate this risk by ensuring prudent expenditures, seeking from the regulator clear policy direction on cost responsibility, and pre-approval of the need for capital expenditures.

While we expect all of our expenditures to be fully recoverable after OEB review, any future regulatory decision to disallow or limit the recovery of such costs would lead to potential asset impairment and charges to our results of operations, which could have a material adverse effect on our company.

In Ontario, the Market Rules mandate that we comply with the reliability standards established by North American Electric Reliability Corporation and Northeast Power Coordinating Council Inc. As a result, we will be required to comply with the Federal Energy Regulatory Commission's definition of "bulk electric system" unless we are granted an exemption which will allow the application of the new definition in a cost-effective manner. We will look for recovery for costs incurred in meeting the definition in our rates; however an adverse decision on an exemption for recovery of costs could have an adverse effect on our company.

Risk Associated with Arranging Debt Financing

We expect to borrow to repay our existing indebtedness and fund a portion of capital expenditures. We have substantial amounts of existing debt which mature between 2013 and 2016, including $600 million maturing in 2013 and $750 million maturing in 2014. We plan to incur capital expenditures of approximately $1.6 billion in 2013 and $1.8 billion in 2014. Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of our existing indebtedness and capital expenditures. Our ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by numerous factors, including the regulatory environment in Ontario, our results of operations and financial position, market conditions, the ratings assigned to our debt securities by credit rating agencies and general economic conditions. Any failure or inability on our part to borrow substantial amounts of debt on satisfactory terms could impair our ability to repay maturing debt, fund capital expenditures and meet other obligations and requirements and, as a result, could have a material adverse effect on our company.

Risk Associated with Transmission Projects

The amount of power that can flow through transmission networks is constrained due to the physical characteristics of transmission lines and operating limitations. Within Ontario, new and expected generation facility connections, including those renewable energy generation facilities connecting as a result of the FIT program stemming from the GEA, and load growth have increased such that parts of our transmission and distribution systems are operating at or near capacity. These constraints or bottlenecks limit the ability of our network to reliably transmit power from new and existing generation sources (including expanded interconnections with neighbouring utilities) to load centres or meet customers' increasing loads. As a result, investments have been initiated to increase transmission capacity and enable the reliable delivery of power from existing and future generation sources to Ontario consumers.

In many cases, these investments are contingent upon one or more of the following approvals and/or processes: environmental approval(s); receipt of OEB approvals which can include expropriation; and appropriate consultation processes with First Nations and Métis. Obtaining OEB and/or environmental assessment approvals and carrying out these processes may also be impacted by opposition to the proposed site of transmission investments which could adversely affect transmission reliability and/or our service quality, both of which could have a material adverse effect on our company.

With the introduction on August 26, 2010 of the OEB's competitive transmission project development planning process, in the absence of a government directive, all interested transmitters will be required to submit a bid to the OEB for identified enabler facilities and network enhancement projects. Historically, we would have been awarded such projects through our rates and Section 92, Leave to Construct, applications. The facilitation of competitive transmission could impact our future work program and our ability to expand our current transmission footprint. In addition, bid costs are only recoverable by the successful proponent. This could have a material adverse effect on our company.

Asset Condition

We continually monitor the condition of our assets and maintain, refurbish or replace them to maintain equipment performance and provide reliable service quality. Our capital programs have been increasing to maintain the performance of our aging asset base. Execution of these plans is partially dependent on external factors, such as outage planning with the IESO and transmission-connected customers, funding approval by the OEB, and supply chain availability for equipment suppliers and consulting services. In addition, opportunities to remove equipment from service to accommodate construction and maintenance are becoming increasingly limited due to customer and generator priorities.

Adjustments to accommodate these external dependencies have been made in our planning process, and we are focused on overcoming these challenges to execute our work programs. However, if we are unable to carry out these plans in a timely and optimal manner, equipment performance will degrade which may compromise the reliability of the provincial grid, our ability to deliver sufficient electricity and/or customer supply security and increase the costs of operating and maintaining these assets. This could have a material adverse effect on our company.

Workforce Demographic Risk

By the end of 2012, approximately 18% of our employees were eligible for retirement and by 2013 there could be up to 20% eligible to retire. Accordingly, our success will be tied to our ability to attract and retain sufficient qualified staff to replace those retiring. This will be challenging as we expect the skilled labour market for our industry to be highly competitive in the future. In addition, many of our employees possess experience and skills that will also be highly sought after by other organizations both inside and outside the electricity sector. We are therefore focused on earlier identification and more rapid development of staff who demonstrate management potential. Moreover, we must also continue to advance our technical training and apprenticeship programs and succession plans to ensure that our future operational staffing needs will be met. If we are unable to attract and retain qualified personnel, it could have a material adverse effect on our business.

Environmental Risk

Our health, safety and environmental management system is designed to ensure hazards and risks are identified and assessed, and controls are implemented to mitigate significant risks. This system includes a standing committee of our Board of Directors that has governance over environmental matters. Given the territory that our system encompasses and the amount of equipment that we own, we cannot guarantee, however, that all such risks will be identified and mitigated without significant cost and expense to our company. The following are some of the areas that may have a significant impact on our operations.

We are subject to extensive Canadian federal, provincial and municipal environmental regulation. Failure to comply could subject us to fines and other penalties. In addition, the presence or release of hazardous or other harmful substances could lead to claims by third parties and/or governmental orders requiring us to take specific actions such as investigating, controlling and remediating the effects of these substances. We are currently undertaking a voluntary land assessment and remediation (LAR) program covering most of our stations and service centres. This program involves the systematic identification of any contamination at or from these facilities, and, where necessary, the development of remediation plans for our company and adjacent private properties. Any contamination of our properties could limit our ability to sell these assets in the future.

We record a liability for our best estimate of the present value of the future expenditures required to comply with Environment Canada's PCB regulations and for the present value of the future expenditures to complete our LAR program. The future expenditures required to discharge our PCB obligation are expected to be incurred over the period ending 2025, while our LAR expenditures are expected to be incurred over the period ending 2020. Actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on our balance sheet. We do not have insurance coverage for these environmental expenditures.

Under applicable regulations, we expect to incur future expenditures to identify, remove and dispose of asbestos-containing materials installed in some of our facilities. We record an asset retirement obligation for the present value of the estimated future expenditures. The estimates are based on an external, expert study of the current expenditures associated with removing such materials from our facilities. Actual future expenditures may vary materially from the estimates used for the amount of the asset retirement obligation.

There is also risk associated with obtaining governmental approvals, permits, or renewals of existing approvals and permits related to constructing or operating facilities. This may require environmental assessment or result in the imposition of conditions, or both, which could result in delays and cost increases.

We anticipate that all of our future environmental expenditures will continue to be recoverable in future electricity rates. However, any future regulatory decision to disallow or limit the recovery of such costs could have a material adverse effect on our company.

Scientists and public health experts have been studying the possibility that exposure to electric and magnetic fields emanating from power lines and other electric sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health risk, or governments decide to implement exposure limits, we could face litigation, be required to take costly mitigation measures such as relocating some of our facilities or experience difficulties in locating and building new facilities. Any of these could have a material adverse effect on our company.

Risk of Natural and Other Unexpected Occurrences

Our facilities are exposed to the effects of severe weather conditions, natural disasters, man-made events including cyber and physical terrorist type attacks and, potentially, catastrophic events, such as a major accident or incident at a facility of a third party (such as a generating plant) to which our transmission or distribution assets are connected. Although constructed, operated and maintained to industry standards, our facilities may not withstand occurrences of this type in all circumstances. We do not have insurance for damage to our transmission and distribution wires, poles and towers located outside our transmission and distribution stations resulting from these events. Losses from lost revenues and repair costs could be substantial, especially for many of our facilities that are located in remote areas. We could also be subject to claims for damages caused by our failure to transmit or distribute electricity. Our risk is partly mitigated because our transmission system is designed and operated to withstand the loss of any major element and possesses inherent redundancy that provides alternate means to deliver large amounts of power. In the event of a large uninsured loss we would apply to the OEB for recovery of such loss; however, there can be no assurance that the OEB would approve any such applications, in whole or in part, which could have a material adverse effect on our net income.

Risk Associated with Information Technology Infrastructure

Our ability to operate effectively in the Ontario electricity market is in part dependent upon us developing, maintaining and managing complex IT systems which are employed to operate our transmission and distribution facilities, financial and billing systems, and business systems. Our increasing reliance on information systems and expanding data networks increases our exposure to information security threats. We mitigate this risk through various methods including the use of security event management tools on our power and business systems, by separating our power system network from our business system network, by performing scans of our systems for known cyber threats and by providing company-wide awareness training to our personnel. We also engage the services of external experts to evaluate the security of our IT infrastructure and controls. We perform vulnerability assessments on our critical cyber assets and we ensure security and privacy controls are incorporated into new IT capabilities. Although these security and system disaster recovery controls are in place, there can be no guarantee that there will not be system failures or security breaches. Upon occurrence, the focus would shift from prevention to isolation, remediation and recovery until the incident has been fully addressed. Any such system failures or security breaches could have a material adverse effect on our company.

We are currently in the process of a planned phased replacement of key enterprise IT systems. The last phase of this project is underway and will replace our existing billing and customer system with a new CIS. With projects of this size and complexity, there is risk to the Company if the resulting solution encounters performance problems or calculation errors. Any such system problems could have a material adverse effect on our company. To mitigate this risk, extensive testing and user training is taking place. Testing includes performance, system integration, parallel billing (comparing legacy system bill calculation to the new system), and operational/business readiness. Since this system directly impacts our end customers, stringent test exit criteria must be met prior to placing it into production.

Pension Plan Risk

We have a defined benefit registered pension plan for the majority of our employees. Contributions to the pension plan are established by actuarial valuations which are filed with the Financial Services Commission of Ontario on a triennial basis. The most recently filed valuation was prepared as at December 31, 2011 and was filed in May 2012. Our company contributed $148 million in respect of 2011 and approximately $160 million in respect of 2012 to its pension plan to satisfy minimum funding requirements. An additional contribution of $3.8 million was also made in 2011 to complete the funding associated with the partial plan wind-up. Contributions beyond 2012 will depend on investment returns, changes in benefits and actuarial assumptions and may include additional voluntary contributions from time to time. Nevertheless, future contributions are expected to be significant. A determination by the OEB that some of our pension expenditures are not recoverable from customers could have a material adverse effect on our company, and this risk may be exacerbated as the quantum of required pension contributions increase.

Market and Credit Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. We do not have commodity risk. We do have foreign exchange risk as we enter into agreements to purchase materials and equipment associated with our capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material. We could in the future decide to issue foreign currency-denominated debt which we would anticipate hedging back to Canadian dollars, consistent with our company's risk management policy. We are exposed to fluctuations in interest rates as our regulated rate of return is derived using a formulaic approach. The OEB-approved adjustment formula for calculating ROE will increase or decrease by 50% of the change between the current Long Canada Bond Forecast and the risk-free rate established at 4.25% and 50% of the change in the spread in 30-year "A"-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield established at 1.415%. We estimate that a 1% decrease in the forecasted long-term Government of Canada bond yield used in determining our rate of return would reduce our Transmission Business' net income by approximately $19 million and our Hydro One Networks' Distribution Business' net income by approximately $10 million. Our net income is adversely impacted by rising interest rates as our maturing long-term debt is refinanced at market rates. We periodically utilize interest-rate swap agreements to mitigate elements of interest-rate risk.

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counterparty default. We monitor and minimize credit risk through various techniques, including dealing with highly-rated counterparties, limiting total exposure levels with individual counterparties, and by entering into master agreements which enable net settlement and by monitoring the financial condition of counterparties. We do not trade in any energy derivatives. We do, however, have interest-rate swap contracts outstanding from time to time. Currently, there are no significant concentrations of credit risk with respect to any class of financial assets. We are required to procure electricity on behalf of competitive retailers and embedded LDCs for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into our service agreements with these retailers in accordance with the OEB's Retail Settlements Code. The failure to properly manage these risks could have a material adverse effect on our company.

Labour Relations Risk

The substantial majority of our employees are represented by either the Power Workers' Union (PWU) or the Society of Energy Professionals. Over the past several years, significant effort has been expended to increase our flexibility to conduct operations in a more cost-efficient manner. Although we have achieved improved flexibility in our collective agreements, including a reduction in pension benefits for Society staff hired after November 2005 similar to a previous reduction affecting management staff, we may not be able to achieve further improvement. The existing collective agreement with the PWU will expire on March 31, 2013 and the existing Society collective agreement will expire on March 31, 2013. We face financial risks related to our ability to negotiate collective agreements consistent with our rate orders. In addition, in the event of a labour dispute, we could face operational risk related to continued compliance with our licence requirements of providing service to customers. Any of these could have a material adverse effect on our company.

First Nation and Métis Claims Risk

Some of our current and proposed transmission and distribution lines may traverse lands over which First Nations and Métis have aboriginal, treaty or other legal claims. Although we have a recent history of successful negotiations and consultations with First Nations and Métis in Ontario, some communities and/or their citizens have expressed an increasing willingness to assert their claims through the courts, tribunals, or by direct action, which in turn can affect business activities. As a result, there exists uncertainty relating to business operations and project planning which could have an adverse effect on our company.

Risk from Transfer of Assets Located on Reserves

The transfer orders by which we acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves. Currently, OEFC holds legal title to these assets and we manage them until we have obtained necessary authorizations to complete the title transfer. To occupy Reserves, we must have valid permits issued by Her Majesty the Queen in the Right of Canada. For each permit, we must negotiate an agreement (in the form of a Memorandum of Understanding) with the First Nation, OEFC and any members of the First Nation who have occupancy rights. The agreement includes provisions whereby the First Nation consents to the federal Department of Aboriginal Affairs and Northern Development issuing a permit. It is difficult to predict the aggregate amount that we may have to pay, either on an annual or one-time basis, to obtain the required agreements from First Nations. However, we anticipate that the amount will exceed the approximately $943,000 that we paid in 2012. OEFC will continue to hold these assets until we are able to negotiate agreements with First Nations and occupants. If we cannot reach satisfactory agreements and obtain federal permits, we may have to relocate these assets to other locations at a cost that could be substantial. In a limited number of cases, it may be necessary to abandon a line and replace it with diesel generation facilities. The costs relating to these assets could have a material adverse effect on our net income if we are not able to recover them in future rate orders.

Risk Associated with Outsourcing Arrangement

Consistent with our strategy of reducing operating costs, we amended and extended our outsourcing services agreement with Inergi, effectively renewing the arrangement until February 28, 2015. If the agreement with Inergi is terminated for any reason, we could be required to incur significant expenses to transfer to another service provider, which could have a material adverse effect on our business, operating results, financial condition or prospects.

Risk from Provincial Ownership of Transmission Corridors

Pursuant to the *Reliable Energy and Consumer Protection Act, 2002*, the Province acquired ownership of our transmission corridor lands underlying our transmission system. Although we have the statutory right to use the transmission corridors, we may be limited in our ability to expand our systems. Also, other uses of the transmission corridors by third parties in conjunction with the operation of our systems may increase safety or environmental risks, which could have an adverse effect on our company.

CRITICAL ACCOUNTING ESTIMATES

The preparation of our Consolidated Financial Statements requires us to make estimates and judgements that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. We base our estimates and judgements on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgements about the carrying values of assets and liabilities as well as identifying and assessing our accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgements under different assumptions or conditions.

We believe the following critical accounting estimates involve the more significant estimates and judgements used in the preparation of our Consolidated Financial Statements:

Regulatory Assets and Liabilities

At December 31, 2012, regulatory assets amounted to $3,127 million and these amounts principally relate to regulatory offsets to pension, deferred income tax, post-retirement and post-employment benefits and environmental liabilities, which are anticipated to be recovered through rates over time. We have also recorded regulatory liabilities amounting to $221 million as at December 31, 2012. These amounts pertain primarily to OEB deferral and variance accounts. These assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the relevant amounts have been approved for inclusion in the rate-setting process by the OEB or if such approval is judged to be probable by management. If management judges that it is no longer probable that the OEB will include a regulatory item in the setting of future rates, the relevant regulatory asset or liability would be charged or credited to results of operations in the period in which that judgement is made.

Environmental Liabilities

We record liabilities and related regulatory assets based on the present value of the estimated future expenditures to be made to satisfy obligations related to legacy environmental contamination inherited upon our de-merger from Ontario Hydro in 1999. These liabilities fall into two main categories: the management of assets contaminated with PCB-laden mineral oils and the assessment and remediation of contaminated lands. In determining the amounts to be recorded as environmental liabilities, we estimate the current cost of completing mitigation work now and make assumptions for when the future expenditures will actually be incurred in order to generate future cash flow information. A long-term inflation assumption of 2% is used to express our current cost estimates as estimated future expenditures. Future estimated LAR expenditures are expected to be incurred over the period ending 2020 and are discounted using factors ranging from 3.57% to 4.87%, depending on the appropriate rate for the period when the particular obligation was recorded. Consistent with the current requirements of Environment Canada's PCB regulations, estimated future PCB remediation expenditures are expected to be incurred over the period ending 2025 and are discounted using factors ranging from 5.14% to 6.25%, depending on the appropriate rate in effect in the period when each obligation was originally recorded.

Recording a liability for such long-term future expenditures requires that many other assumptions be made, such as the number of contaminated properties and the extent of contamination; the number of assets to be inspected, tested and mitigated; oil volumes; contamination levels of equipment that may have PCBs; and the timing of work. All factors used in deriving our environmental liabilities represent management's best estimates based on our planned approach of meeting current legislative and regulatory requirements. These requirements include Environment Canada's regulations governing the management, storage and disposal of PCBs. However, it is reasonably possible that numbers or volumes of contaminated assets, current cost estimates, inflation estimates and the actual pattern of annual future cash flows may differ significantly from our current assumptions. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant facts occur. Regulatory changes are reflected when enacted. Estimate changes are accounted for prospectively.

Employee Future Benefits

We provide future benefits to our current and retired employees, including pension, group life insurance, health care and long-term disability.

In accordance with our rate orders, we record pension costs when employer contributions are paid to the pension fund (the Fund) in accordance with the *Pension Benefits Act* (Ontario). Our annual pension contributions in respect of 2012 were approximately $160 million, based on an actuarial valuation effective December 31, 2011. Contributions after 2014 will be based on an actuarial valuation effective no later than December 31, 2014, and will depend on investment returns, changes in benefits or actuarial assumptions. Pension costs are also disclosed in the notes to the Consolidated Financial Statements on an accrual basis. The discount rate used to calculate the accrued benefit obligation, on an accrual accounting basis, is calculated differently from what would be used to determine the funding requirement, and is determined each year end by referring to the most recently available market interest rates based on AA corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rates at December 31, 2012 declined to 4.25% from 5.25% used at December 31, 2011, in conjunction with decreases in bond yields over this period. The decrease in discount rates has resulted in a corresponding increase in liabilities for accounting purposes. We also record employee future benefit costs other than pension on an accrual accounting basis. The accrual costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. The assumptions were determined by management recognizing the recommendations of our actuaries. There were no changes in benefits afforded to employees.

The assumed return on pension plan assets of 6.25% per annum is based on expectations of long-term rates of return at the beginning of the fiscal year and reflects a pension asset mix consistent with the Fund's investment policy. During the year the Fund's target asset mix was 60% equities, 35% fixed income and 5% in alternative assets consisting of real estate and infrastructure. Returns on the respective portfolios are determined with reference to published Canadian and U.S. stock indices and long-term bond and treasury bill indices. The assumed rate of return on pension plan assets reflects our long-term expectations. We believe that this assumption is reasonable because, with the Fund's balanced investment approach, the higher volatility of equity investment returns is intended to be offset by the greater stability of fixed-income and short-term investment returns. The net result, on a long-term basis, is a somewhat lower return than might be expected by investing in equities alone. In the short term, the plan can experience aberrations in actual return. In 2012, the return on pension plan assets of 9.19% was higher than this long-term assumption and was higher than in 2011.

Yields on AA corporate bonds declined by approximately 80-100 basis points between December 31, 2011 and December 31, 2012. Based on the duration of the plan's liabilities, discount rates would be 4.25% per annum for each of the pension plan, the post-retirement benefit plan and the post-employment plan. The overall discount rate applied to all plans for liability accounting purposes as at December 31, 2012 was 4.25%.

Further, based on differences between long-term Government of Canada nominal bonds and real return bonds, the implied inflation rate has decreased from 2.0% per annum as at December 31, 2011 to approximately 1.90% per annum as at December 31, 2012. Given the Bank of Canada's commitment to keep long-term inflation between 1.00% and 3.00%, management believes that the current implied rate is reasonable to use as a long-term assumption and as such, has used a 2.0% per annum inflation rate for liability valuation purposes as at December 31, 2012.

The costs of employee future benefits other than pension are determined at the beginning of the year. The costs are based on assumptions for expected claims experience and future health care cost inflation. A 1% increase in the health care cost trends would result in an increase in service cost and interest cost of about $17 million per year and an increase in the year-end obligation of about $246 million.

Employee future benefits are included in labour costs that are either charged to results of operations or capitalized as part of the cost of fixed and intangible assets. Changes in assumptions will affect the accrued benefit obligation of the employee future benefits and the future years' amounts that will be charged to our results of operations or capitalized as part of the cost of fixed and intangible assets.

Asset Impairment

Within our regulated businesses, carrying costs of our other assets are recovered in our revenue requirements and are included in rate base, where they earn a return. Such assets would need to be tested for impairment only in the event that the OEB disallowed recovery or if such a disallowance was judged to be probable. We periodically monitor the assets of our unregulated Telecom Business for indications of impairment. No asset impairments have been recorded to date within any of our businesses.

TRANSITION TO US GAAP

Accounting Framework for External Reporting

In 2011, the OSC and our Board of Directors approved our application to adopt US GAAP as the basis for our accounting, external financial reporting and periodic securities filings, without becoming a Securities and Exchange Commission (SEC) registrant, for our 2012, 2013 and 2014 fiscal years. As a result, our Consolidated Financial Statements and accompanying notes as at, and for the year ended, December 31, 2012 have been prepared in accordance with US GAAP. These are our first US GAAP annual Consolidated Financial Statements. Our first US GAAP unaudited interim Consolidated Financial Statements were as at, and for the three months ended, March 31, 2012.

Our company's Consolidated Financial Statements were prepared in accordance with Part V of the Canadian Institute of Chartered Accountants (CICA) Handbook until December 31, 2011. Canadian GAAP differs in some areas from US GAAP as disclosed in the reconciliation to US GAAP included in Note 24 to the annual Consolidated Financial Statements as at, and for the year ended, December 31, 2012. Descriptions of the effect of the transition from Canadian GAAP to US GAAP on our financial position, financial performance and cash flows as at, and for the year ended, December 31, 2011 are also provided in Note 24 to our annual Consolidated Financial Statements for the year ended December 31, 2012. The accounting policies set out in the annual Consolidated Financial Statements for the year ended December 31, 2012 have been consistently applied to all the periods presented. The comparative figures in respect of 2011 were retrospectively restated effective January 1, 2011 to reflect our adoption of US GAAP.

Accounting Framework for Rate Setting

Consistent with the OSC's decision to approve our adoption of US GAAP, two of our subsidiaries, Hydro One Networks and Hydro One Remote Communities requested that the OEB approve the adoption of US GAAP as the basis for future rate setting and regulatory accounting and reporting in place of its standard modified IFRS basis. The OEB approved Hydro One Networks' request to adopt US GAAP for its regulated transmission and distribution businesses, and approved Hydro One

Remote Communities' request to adopt US GAAP as its approved basis for rate setting, all effective January 1, 2012. We did not make a request to adopt US GAAP for rate-setting purposes on behalf of our subsidiary, Hydro One Brampton Networks. Our subsidiary Hydro One Brampton Networks has deferred its adoption of modified IFRS until the fiscal year beginning January 1, 2014, as allowed by the Canadian Accounting Standards Board. Currently, Hydro One Brampton Networks will continue to have its rates set based on Part V of the CICA Handbook until it begins reporting under modified IFRS.

Debt Covenants

None of our financial covenants were impacted by our conversion to US GAAP.

Internal Controls over Financial Reporting and Disclosure Controls and Procedures

Our transition to US GAAP did not result in any significant revisions to our internal controls over financial reporting and disclosure controls and procedures.

Financial Reporting Expertise

Given the similarities between US GAAP and Canadian GAAP for our company, there has also been no significant impact from the transition to US GAAP with respect to financial reporting expertise. Our US GAAP training efforts have been focused on specific areas of difference between the two accounting frameworks and these efforts have been targeted to specific finance staff, senior executive management and the Audit and Finance Committee of our Board of Directors. We continue to provide additional training to our other finance and operational staff, concentrating on communicating the key differences between Canadian and US GAAP at a level of detail that is appropriate to meet their respective needs. During 2013, we will continue to focus our US GAAP training on new accounting and reporting developments and on emerging issues.

Information Systems

Given the similarities between US GAAP and Canadian GAAP, we did not experience any significant impacts from the transition to US GAAP with respect to our information systems.

IFRS

Prior to our adoption of US GAAP as the basis for our accounting, external financial reporting and periodic securities filings, we had planned to adopt IFRS effective January 1, 2012, with comparative restatement of our 2011 results. Accordingly, by mid-2011, we had substantively completed our four-phase IFRS Conversion Project, which included separate diagnostic, design and planning, solution development, and implementation phases. Our IFRS conversion project involved, among other initiatives, a detailed assessment of the effects of IFRS on our financial statements, a review and upgrade of our information systems to meet IFRS requirements, an assessment of our internal controls over financial reporting and disclosure controls and processes, as well as training of our key finance and operational staff.

As a result of our 2011 decision to adopt US GAAP, our IFRS Conversion Project efforts were effectively halted. However, our IFRS conversion work has been, and will continue to be, managed in such a way that it can effectively be restarted if a future transition to IFRS is required. We continue to monitor major accounting developments arising from initiatives of the international standard setter, particularly as several major projects are joint efforts with the US Financial Accounting Standards Board.

Training of our key finance and operational staff commenced in 2007, and continues on a reduced but ongoing basis, as we have certain subsidiaries that are required to prepare their own separate financial statements in accordance with IFRS. IFRS training was also previously provided to our Audit and Finance Committee and senior executive management. In 2013, we will continue to monitor new IFRS accounting and reporting developments and emerging issues and will provide IFRS training to specific staff as applicable.

Our company has the customary financial covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization. Depending on the outcome of various international standard setting initiatives, including the International Accounting Standards Board's (IASB) Rate

Regulated Accounting Project, a potential future adoption of IFRS could result in changes to our financial position and increased volatility in our results of operations that could impact our debt covenants. We continue to monitor the potential impact that an IFRS conversion could have under various scenarios.

As part of a company-wide information systems improvement project, many of our major financial systems were replaced in 2008 and 2009. Our new financial systems were designed with maximum flexibility given the uncertainty of the outcome of certain impactive IASB projects. Our financial systems have the ability and capacity to handle current accounting and reporting processes in accordance with IFRS, should that be required in the future.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING (ICFR)

To optimize our customer service operations, we have started the final major phase of our planned SAP enterprise-wide information system by initiating our CIS Project. This new system will increase productivity by replacing multiple legacy applications currently providing service to our distribution customers and key constituents for billing, customer contacts, field services, settlements and customer choice administration. With the design phase complete, the CIS Project is currently in the system integration phase. Internal controls have been documented and will be tested for adequacy and effectiveness with any remediation effort to be completed prior to the go-live date in 2013. In addition to the benefits associated with our CIS, we continue to leverage our other SAP enterprise systems to gain other productivity improvements.

In compliance with the requirements of National Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the year ended December 31, 2012, together with other financial information included in our annual securities filings. Our Certifying Officers have also certified that disclosure controls and procedures (DC&P) have been designed to provide reasonable assurance that material information relating to our company is made known within our company. Based on the evaluation of the design and operation of our DC&P, our Certifying Officers concluded that our DC&P was effective as at December 31, 2012. Further, our Certifying Officers have also certified that our ICFRs have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of Consolidated Financial Statements. Based on the evaluation of the design and operating effectiveness of our company's ICFR, our Certifying Officers concluded that our ICFR was effective as at December 31, 2012.

SELECTED ANNUAL INFORMATION

The following table sets forth audited annual information for each of the three years ended December 31, 2012, 2011 and 2010. This information has been derived from our audited annual Consolidated Financial Statements.

Consolidated Statements of Operations

Year ended December 31 (millions of dollars, except amounts per share)	**2012**	**2011**	**2010[1]**
Revenues	5,728	5,471	5,124
Net income	745	641	591
Basic and fully diluted earnings per common share	7,280	6,228	5,727
Cash dividends per common share	3,523	1,500	100
Cash dividends per preferred share	1,375	1,375	1,375

Consolidated Balance Sheets

December 31 (millions of dollars)	**2012**	**2011**	**2010**
Total assets	20,811	18,836	17,344
Total long-term debt	8,479	8,008	7,783

[1] Based on Canadian GAAP. US GAAP results would not differ significantly.

OUTLOOK

To achieve our mission and vision to be an innovative and trusted company delivering electricity safely, reliably and efficiently to create value for our customers, we will continue to concentrate on our strategic objectives of safety, customer satisfaction, continuous innovation, reliability, protection of the environment, employee engagement, shareholder value and productivity and cost-effectiveness. Given the nature of the work undertaken by our employees and contractors, safety remains our top priority. We will continue to focus on creating an injury-free workplace and maintaining public safety through several health and safety initiatives.

We will continue to focus our efforts to improve our customers' satisfaction by meeting the unique needs of our diverse customer base through dialogue to understand their needs. We will install innovative solutions that improve the reliability and efficiency of the transmission and distribution systems and provide our customers more capability to manage their own costs. Most importantly, we are focused on becoming the customer's trusted advisor by providing access to specialized energy conservation teams to discuss the customer's opportunities to lower consumption, and through the use of a special team of agents to handle distributed generator inquiries and requirements.

Our assets are in the midst of a demographic change with an increasing proportion of assets reaching end-of-life and an increasing average asset age. Our focus is to address aging infrastructure, and to make needed asset replacement and maintenance investments, to maintain current and future system reliability for customers, within the policy set by the OEB. We will invest in technology that will provide us with real time asset condition and performance data giving us the visibility to make asset optimization life-cycle decisions, and opportunities through planning and scheduling data to improve materials procurement and to deploy work crews to better manage work programs to meet customer needs.

It is expected that the implementation of new asset management tools, such as Asset Analytics and Asset Investment Planning, will enhance risk-based investment planning, which considers such factors as asset condition, safety, performance, system function, customer impact, and statutory requirements allowing for targeted investment.

We will also continue to strive for productivity through efficiency and effective management of costs, which is key to achieving value for our customers and our shareholder.

Over the last four years, we have replaced most of our core information technology systems with an enterprise-wide IT system. We will leverage this investment as a platform for further effectiveness and efficiency gains, including enhancements in strategic sourcing. Further development of the existing IT platform will provide tools which are being developed to allow our company to effectively plan and reprioritize work and integrate customers' needs into multi-year investment plans. The outcomes are consistent with the OEB's direction in its new Outcomes-Based Approach to regulation.

We will be implementing the new CIS in 2013 that will improve customer service and corporate productivity by allowing the earlier investments in SAP to operate as an integrated platform. In addition, the first elements of the next generation of work delivery to be introduced through the Workflow of the Future Program in 2013 and 2014, and the use of information within the SAP systems, are expected to improve field-level productivity.

We are planning significant investments in transmission and distribution infrastructure and we will continue to focus on the operating and economic performance of our core utility operations in the provision of safe, cost-effective and reliable electricity delivery services to our customers, and in providing increasing enterprise value to the people of the province of Ontario. Productivity, value for money and improved employee and customer communications will be key areas of focus. We will continue to connect and support DG and investments made consistent with the LTEP.

Significant opportunity resides with smart meters and the proliferation of an ADS, including energy efficiency, demand response and distributed-resources technologies. We will invest in the development of an ADS and related grid modernization standards, customer demand work (connections and upgrades), smart meters, DG connections, including station upgrades, protection and control, new lines and some contestable work, for which the Company will receive capital contributions. There is little flexibility to reduce this work as most of it is customer demand driven.

As part of our new ADS, a new DMS will provide a monitoring and centralized control capability similar to that which already exists in the transmission system, and in selected areas of the distribution system. The new DMS was introduced in the Owen Sound pilot area and it will be expanded over time, as warranted. Future enhancements will also integrate the

Outage Response Management System with the Advanced Meter Infrastructure (i.e. smart meters) and with the DMS, to reduce System Average Interruption Duration Index and System Average Interruption Frequency Index.

The actual timing and expenditures in our business plan are predicated on obtaining various approvals including: OEB approvals and environmental assessment approvals; successful negotiations with customers, neighbouring utilities and other stakeholders; and consultations with First Nations and Métis communities.

As stewards of significant electricity assets, we are committed to the protection and sustainment of the environment for future generations. We are working towards being an environmental leader in our industry, by distributing clean and renewable energy, by upgrading our electricity grid, by minimizing the impacts of our own operations, and by ensuring that environmental factors are considered in making our business decisions.

Key enablers of the successful implementation of our work programs are our human and material resourcing strategies. Our human resource strategy is focused on hiring through our apprenticeship program and our association with universities, colleges and our unions, as well as skills development and retention, including earlier identification and more rapid development of staff who demonstrate management potential. Effective use of human resources and ensuring correct skills will be critical to attaining the balance between meeting the asset needs and mitigating rate impact on the customer. Although our work program is assumed to grow moderately over the 2013 and 2014 years, no increase in regular staff numbers is anticipated over that period. With regard to materials, we are seeing a need for increasing lead times and costs as market shortages emerge globally. Consequently, materials sourcing strategies continue to be developed and implemented to ensure the availability of materials to support our work programs.

We remain committed to a prudent and measured approach to distribution rationalization. We have considered and will continue to consider and respond to opportunities for acquisitions or divestitures, on a voluntary and commercial basis. Our plan does not include funding for LDC acquisitions or assume any disposition of our service territory. These opportunities will be managed as they arise. Our plan also does not incorporate any projects related to competitive transmission. However, as leaders in the sector, we plan to bid on key projects. The OEB notes in its *Framework for Transmission Project Development Plans* that where projects are otherwise equivalent or close in other factors, information such as socio-economic benefits, including First Nations involvement, could prove decisive in a competitive bid. As such, First Nations involvement in competitive bids is likely to become more prevalent.

APPOINTMENT OF CARMINE MARCELLO

On November 14, 2012, our Board of Directors appointed Carmine Marcello to the role of President and Chief Executive Officer, effective January 1, 2013. Mr. Marcello assumes his responsibilities following the planned retirement of outgoing President and Chief Executive Officer, Laura Formusa. Mr. Marcello has over 25 years' experience with our company as a senior executive, strategic planner and advisor on transmission and distribution utility processes in the electric utility industry.

APPOINTMENT OF YEZDI PAVRI

On December 6, 2012, Yezdi Pavri was appointed to our Board of Directors. Mr. Pavri is a Chartered Accountant and a former Vice-Chairman of Deloitte Canada. Mr. Pavri currently holds the position of Chair of the Board of Trustees of the United Way of Toronto.

FORWARD-LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate, and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to: statements about our strategy, including our strategic objectives; statements regarding our transmission and distribution rates; statements regarding load changes and associated impacts; statements regarding CDM programs and targets; the estimated impact of changes in the forecasted long-term Government of Canada bond yield (used in determining our regulated rate of return) on our results of operations; statements related to economic conditions; expectations regarding energy-related revenues and profit and their trend; statements related to the GEA, the IPSP and the Ministry's LTEP and Supply Mix Directive, including additional investments arising therefrom and the timing and content of OPA recommendations; statements regarding our liquidity and capital resources and operational requirements; statements about our standby credit facility; expectations regarding our financing activities; statements regarding our maturing debt; statements regarding our ongoing and planned projects and/or initiatives including the expected results of these projects and/or initiatives and their completion dates; expectations regarding the recoverability of large capital expenditures; statements regarding expected future capital and development expenditures, the timing of these expenditures and our investment plans; statements regarding contractual obligations and other commercial commitments; statements related to the OEB, including the renewed regulatory framework and revenue decoupling; statements regarding future pension contributions, our pension plan and actuarial valuation; statements about our outsourcing arrangement with Inergi; statements relating to US GAAP and our adoption of US GAAP; statements regarding accounting-related international standard setting initiatives, including the potential future adoption of IFRS and its associated impacts as well as our training and conversion plans; statements related to our agreement with the SON; statements related to our outlook including statements regarding our approach to distribution rationalization; and statements related to the FIT program. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target", and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation, to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; no delays in obtaining required approvals; no unforeseen changes in rate orders or rate structures for our Distribution and Transmission businesses; a stable regulatory environment; no unfavourable changes in environmental regulation; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third-party sources. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the impact of the GEA and the Province's Long-Term Energy Plan, including unexpected expenditures arising therefrom;
- the risk that unexpected capital expenditures may be needed to support renewable generation or resolve unforeseen technical issues;
- the risks associated with the impending expiry of our collective agreements with both the Society and the PWU;
- the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned;
- the risks associated with the OEB's competitive transmission project development planning process;
- public opposition to and delays or denials of the requisite approvals and accommodations for our planned projects;
- the risks associated with being controlled by the Province including the possibility that the Province may make declarations pursuant to the memorandum of agreement, as well as potential conflicts of interest that may arise between us, the Province and related parties;
- the risks associated with being subject to extensive regulation including risks associated with OEB action or inaction;
- unanticipated changes in electricity demand or in our costs;
- the risk that we are not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures and other obligations;
- the risks associated with the execution of our capital and operation, maintenance and administration programs necessary to maintain the performance of our aging asset base;
- the result of regulatory decisions regarding our revenue requirements, cost recovery and rates;

- the risk to our facilities posed by severe weather conditions, natural disasters or catastrophic events and our limited insurance coverage for losses resulting from these events;
- future interest rates, future investment returns, inflation, and changes in benefits and actuarial assumptions;
- the risks related to our workforce demographic and our potential inability to attract and retain qualified personnel;
- the risks associated with information system security, with maintaining a complex information technology system infrastructure, and with transitioning key enterprise IT systems;
- the risk that the presence or release of hazardous or harmful substances could lead to claims by third parties and/or governmental orders;
- the risk that future environmental expenditures are not recoverable in future electricity rates;
- the risk that it may be determined that exposure to electric and magnetic fields emanating from power lines and other electric sources may cause health problems;
- the risks associated with changes in interest rates;
- the risks of counterparty default on our outstanding derivative contracts;
- the risks associated with current economic uncertainty and financial market volatility;
- the risk that our long-term credit rating would deteriorate;
- the risk that we may incur significant costs associated with transferring assets located on Indian lands;
- the risks associated with the fact that some of our current and proposed transmission and distribution lines may traverse lands which First Nations and Métis have aboriginal, treaty or other legal claims;
- the potential that we may incur significant expenses to replace some or all of the functions currently outsourced if our agreement with Inergi is terminated; and
- the impact of the ownership by the Province of lands underlying our transmission system.

We caution the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail in the section "Risk Management and Risk Factors" in this Management's Discussion and Analysis (MD&A). You should review this section in detail.

In addition, we caution the reader that information provided in this MD&A regarding our outlook on certain matters, including future expenditures, is provided in order to give context to the nature of some of our future plans and may not be appropriate for other purposes.

This MD&A is dated as at February 14, 2013. Additional information about our company, including our Annual Information Form, is available on SEDAR at www.sedar.com.

HYDRO ONE INC.
MANAGEMENT'S REPORT

The Consolidated Financial Statements, Management's Discussion and Analysis (MD&A) and related financial information presented in this Annual Report have been prepared by the management of Hydro One Inc. (Hydro One or the Company). Management is responsible for the integrity, consistency and reliability of all such information presented. The Consolidated Financial Statements have been prepared in accordance with United States Generally Accepted Accounting Principles and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102, Part 5.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgement, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 14, 2013.

In meeting its responsibility for the reliability of financial information, management maintains and relies on a comprehensive system of internal control and internal audit. The system of internal control includes a written corporate conduct policy; implementation of a risk management framework; effective segregation of duties and delegation of authorities; and sound and conservative accounting policies that are regularly reviewed. This structure is designed to provide reasonable assurance that assets are safeguarded and that reliable information is available on a timely basis. In addition, internal and disclosure controls have been documented, evaluated, tested and identified consistent with National Instrument 52-109 (Bill 198). The effectiveness of these internal controls is evaluated and findings are reported to management and the Audit and Finance Committee of the Hydro One Board of Directors, as required.

The Consolidated Financial Statements have been examined by KPMG LLP, independent external auditors appointed by the Hydro One Board of Directors. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with United States Generally Accepted Accounting Principles. The Independent Auditors' Report outlines the scope of their examination and their opinion.

The Hydro One Board of Directors, through its Audit and Finance Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit and Finance Committee of Hydro One met periodically with management, the internal auditors and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit and Finance Committee, with and without the presence of management, to discuss their audit and their findings as to the integrity of the financial reporting and the effectiveness of the system of internal controls.

The Company's President and Chief Executive Officer and Executive Vice-President and Chief Financial Officer have certified Hydro One's annual Consolidated Financial Statements and annual MD&A filed under provincial securities legislation, related disclosure controls and procedures and the design and effectiveness of related internal controls over financial reporting pursuant to National Instrument 52-109.

On behalf of Hydro One Inc.'s management:

Carmine Marcello

Carmine Marcello
President and Chief Executive Officer

Sandy Struthers
Chief Administration Officer and Chief Financial Officer

HYDRO ONE INC.
INDEPENDENT AUDITORS' REPORT

To the Shareholder of Hydro One Inc.

We have audited the accompanying consolidated financial statements of Hydro One Inc., which comprise the consolidated balance sheets as at December 31, 2012 and December 31, 2011, the consolidated statements of operations and comprehensive income, changes in shareholder's equity and cash flows for the years ended December 31, 2012 and December 31, 2011, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with United States Generally Accepted Accounting Principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Hydro One Inc. as at December 31, 2012 and December 31, 2011, and its consolidated statements of operations and comprehensive income, changes in shareholder's equity and cash flows for the years ended December 31, 2012 and December 31, 2011 in accordance with United States Generally Accepted Accounting Principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada
February 14, 2013

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

Year ended December 31 (millions of dollars, except per share amounts)	**2012**	**2011**
Revenues		*(Note 24)*
Distribution (includes $155 related party revenues; 2011 – $155) *(Note 19)*	4,184	4,019
Transmission (includes $1,482 related party revenues; 2011 – $1,372) *(Note 19)*	1,482	1,389
Other	62	63
	5,728	5,471
Costs		
Purchased power (includes $2,409 related party costs; 2011 – $2,427) *(Note 19)*	2,774	2,628
Operation, maintenance and administration *(Note 19)*	1,071	1,092
Depreciation and amortization *(Note 4)*	659	616
	4,504	4,336
Income before financing charges and provision for payments in lieu of corporate income taxes	1,224	1,135
Financing charges *(Note 5)*	358	344
Income before provision for payments in lieu of corporate income taxes	866	791
Provision for payments in lieu of corporate income taxes *(Notes 6, 19)*	121	150
Net income	745	641
Other comprehensive income	1	-
Comprehensive income	746	641
Basic and fully diluted earnings per common share *(dollars) (Note 17)*	7,280	6,228
Dividends per common share declared *(dollars) (Note 18)*	3,523	1,500

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS

December 31 (millions of dollars)	**2012**	**2011**
Assets		*(Note 24)*
Current assets:		
Short-term investments *(Note 12)*	195	228
Accounts receivable (net of allowance for doubtful accounts – $23; 2011 – $18) *(Note 7)*	845	805
Due from related parties *(Note 19)*	154	156
Regulatory assets *(Note 10)*	29	24
Materials and supplies	23	25
Deferred income tax assets *(Note 6)*	18	19
Derivative instruments *(Note 12)*	-	1
Other	22	19
	1,286	1,277
Property, plant and equipment *(Note 8)*:		
Property, plant and equipment in service	22,650	21,008
Less: accumulated depreciation	8,145	7,679
	14,505	13,329
Construction in progress	1,055	1,436
Future use land, components and spares	147	138
	15,707	14,903
Other long-term assets:		
Regulatory assets *(Note 10)*	3,098	1,966
Long-term investment *(Notes 11, 12, 19)*	251	250
Intangible assets (net of accumulated amortization – $305; 2011 – $257) *(Note 9)*	267	224
Goodwill	133	133
Deferred debt costs	34	32
Derivative instruments *(Note 12)*	19	33
Deferred income tax assets *(Note 6)*	14	17
Other	2	1
	3,818	2,656
Total assets	20,811	18,836

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (continued)

December 31 (millions of dollars, except number of shares)	**2012**	**2011**
Liabilities		*(Note 24)*
Current liabilities:		
Bank indebtedness *(Note 12)*	42	39
Accounts payable	140	154
Accrued liabilities *(Notes 6, 14, 15)*	582	575
Due to related parties *(Note 19)*	257	342
Accrued interest	95	85
Regulatory liabilities *(Note 10)*	40	25
Long-term debt payable within one year *(Notes 11, 12)*	600	600
	1,756	1,820
Long-term debt (includes $769 measured at fair value; 2011 – $783) *(Notes 11, 12)*	7,879	7,408
Other long-term liabilities:		
Post-retirement and post-employment benefit liability *(Note 14)*	1,416	1,163
Deferred income tax liabilities *(Note 6)*	944	758
Pension benefit liability *(Note 14)*	1,515	779
Environmental liabilities *(Note 15)*	227	235
Regulatory liabilities *(Note 10)*	181	169
Net unamortized debt premiums	23	23
Asset retirement obligations *(Note 16)*	15	15
Long-term accounts payable and other liabilities	25	12
	4,346	3,154
Total liabilities	13,981	12,382
Contingencies and commitments (Notes 21, 22)		
Preferred shares (authorized: unlimited; issued: 12,920,000) *(Notes 17, 18)*	323	323
Shareholder's Equity		
Common shares (authorized: unlimited; issued: 100,000) *(Notes 17, 18)*	3,314	3,314
Retained earnings	3,202	2,827
Accumulated other comprehensive loss	(9)	(10)
Total shareholder's equity	6,507	6,131
Total liabilities, preferred shares and shareholder's equity	20,811	18,836

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

James Arnett
Chair

Michael J. Mueller
Chair, Audit and Finance Committee

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY

Year ended December 31, 2012 *(millions of dollars)*	**Common Shares**	**Retained Earnings**	**Accumulated Other Comprehensive Loss**	**Total Shareholder's Equity**
January 1, 2012	3,314	2,827	(10)	6,131
Net income	-	745	-	745
Other comprehensive income	-	-	1	1
Dividends on preferred shares	-	(18)	-	(18)
Dividends on common shares	-	(352)	-	(352)
December 31, 2012	3,314	3,202	(9)	6,507

Year ended December 31, 2011 *(millions of dollars)* *(Note 24)*	**Common Shares**	**Retained Earnings**	**Accumulated Other Comprehensive Loss**	**Total Shareholder's Equity**
January 1, 2011	3,314	2,354	(10)	5,658
Net income	-	641	-	641
Other comprehensive income	-	-	-	-
Dividends on preferred shares	-	(18)	-	(18)
Dividends on common shares	-	(150)	-	(150)
December 31, 2011	3,314	2,827	(10)	6,131

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 (millions of dollars)	**2012**	**2011**
Operating activities		*(Note 24)*
Net income	745	641
Environmental expenditures	(18)	(16)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	589	550
Regulatory assets and liabilities	12	47
Deferred income taxes	(9)	(12)
Asset retirement obligations	-	4
Other	6	9
Changes in non-cash balances related to operations *(Note 20)*	(40)	184
Net cash from operating activities	1,285	1,407
Financing activities		
Long-term debt issued	1,085	700
Long-term debt retired	(600)	(500)
Dividends paid	(370)	(168)
Change in bank indebtedness	3	39
Other	(1)	(4)
Net cash from (used in) financing activities	117	67
Investing activities		
Capital expenditures		
Property, plant and equipment	(1,363)	(1,371)
Intangible assets	(91)	(76)
Other	19	29
Net cash used in investing activities	(1,435)	(1,418)
Net change in cash and cash equivalents	(33)	56
Cash and cash equivalents, beginning of year	228	172
Cash and cash equivalents, end of year	195	228

See accompanying notes to Consolidated Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act (Ontario)* and is wholly owned by the Province of Ontario (Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. These businesses are regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

These Consolidated Financial Statements include the accounts of the Company and its wholly-owned subsidiaries: Hydro One Networks Inc. (Hydro One Networks), Hydro One Remote Communities Inc. (Hydro One Remote Communities), Hydro One Brampton Networks Inc. (Hydro One Brampton Networks), Hydro One Telecom Inc. (Hydro One Telecom), Hydro One Lake Erie Link Management Inc., and Hydro One Lake Erie Link Company Inc.

Intercompany transactions and balances have been eliminated.

Basis of Accounting

These Consolidated Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars. These statements are to be read in conjunction with Note 24 – Transition to US GAAP, which discloses information on the Canadian GAAP per Part V of the CICA Handbook (Canadian GAAP) to US GAAP transition and related reconciliations from Canadian GAAP to US GAAP. The results of operations for the year ended December 31, 2011 and the Consolidated Balance Sheet at December 31, 2011 have been restated under US GAAP for comparative purposes. The Company's Consolidated Financial Statements were previously prepared using Canadian GAAP.

Hydro One performed an evaluation of subsequent events for the accompanying Consolidated Financial Statements and notes through to February 14, 2013, the date these Consolidated Financial Statements were issued, to determine whether the circumstances warranted recognition and disclosure of any events or transactions. No such events or transactions were identified.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon: historical experience; current conditions; and assumptions believed to be reasonable at the time the assumptions are made with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, pension benefits, post-retirement and post-employment benefits, asset retirement obligations (AROs), goodwill and asset impairments, contingencies, unbilled revenues, allowance for doubtful accounts, derivative instruments, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates, which may be impacted by future decisions made by the OEB or the Province.

Rate Setting

The Company's consolidated Distribution Business includes the separately regulated distribution businesses of Hydro One Networks, Hydro One Brampton Networks, and Hydro One Remote Communities. The OEB has approved US GAAP as the basis for rate setting for Hydro One Networks' Transmission and Distribution businesses and by Hydro One Remote Communities all effective January 1, 2012. Hydro One Brampton Networks' rates are currently set under Canadian GAAP, and are expected to be set under the OEB's modified International Financial Reporting Standards (IFRS) framework commencing in 2015, once its current Incentive Regulation Mechanism (IRM) period is complete.

Transmission

In May 2010, Hydro One Networks filed a cost-of-service application for 2011 and 2012 transmission rates in continued support of the Company's aging critical infrastructure and the supply mix objectives for generation, including off-coal initiatives and initiation of investments in support of the Green Energy Act (GEA). This application sought the approval of revenue requirements of approximately $1,446 million for 2011 and $1,547 million for 2012.

In December 2010, the OEB approved revenue requirements of $1,346 million for 2011 and $1,658 million for 2012. The approved 2012 revenue requirement was higher than that applied for, reflecting OEB direction to Hydro One to adopt a cost capitalization policy based on modified IFRS. This adjustment was subsequently reversed, when the OEB approved the use of US GAAP for transmission rate-setting purposes beginning January 1, 2012. Consequently, the OEB approved a revenue requirement of $1,418 million for 2012, along with new 2012 uniform transmission rates, with an effective date of January 1, 2012.

Distribution

In 2009, Hydro One Networks filed a cost-of-service application with the OEB for 2011 distribution rates, seeking approval for a revenue requirement of approximately $1,264 million. The application reflected the Company's plan to invest in its network assets to meet objectives regarding public and employee safety, regulatory and legislative compliance, maintenance of system security and reliability of system growth requirements, and to make investments required by the GEA. In April 2010, the OEB approved a revenue requirement of $1,236 million for 2011. The OEB also approved certain distribution regulatory account balances sought by Hydro One Networks in its application, including retail settlement variance accounts, retail cost variance accounts and smart meters. In November 2010, the OEB issued its cost-of-capital parameter updates for rates effective January 1, 2011. A lowering of the return on equity produced a revised revenue requirement of $1,218 million. The approved 2011 revenue requirement resulted in an average distribution rate increase of approximately 8.7% for 2011. Hydro One Networks elected to retain the same distribution rates for 2012 as approved by the OEB for the 2011 rate year.

In 2010, Hydro One Brampton Networks filed a cost-of-service application with the OEB for 2011 distribution rates, seeking approval for a revenue requirement of approximately $63 million. In 2011, the OEB approved a revenue requirement of approximately $60 million for 2011, with an effective date of January 1, 2011. The reduced approved revenue requirement included a reduction to approved operation, maintenance and administration costs. In September 2011, Hydro One Brampton Networks filed an IRM application with the OEB for 2012 distribution rates, with an effective date of January 1, 2012. In January 2012, the OEB released a decision that resulted in a reduction in distribution rates of approximately 13.2% for 2012. These rate reductions were primarily due to OEB-approved adjustments to depreciation rates.

In October 2010, Hydro One Remote Communities filed an IRM application with the OEB for 2011 rates. In March 2011, the OEB approved an increase of approximately 0.4% to basic rates for the distribution and generation of electricity, with an effective date of May 1, 2011. In November 2011, Hydro One Remote Communities filed an IRM application with the OEB for 2012 rates. In March 2012, the OEB approved an increase of approximately 1.1% to basic rates for the distribution and generation of electricity, with an effective date of May 1, 2012.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities that generally represent amounts that are refundable to future electricity customers. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in setting future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

Cash and Cash Equivalents

Cash and cash equivalents include cash and short-term investments. Short-term investments have an original maturity of three months or less.

Revenue Recognition

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as electricity is transmitted and delivered to customers.

Distribution revenues are recognized on an accrual basis and include billed and unbilled revenues. Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized as electricity is delivered to customers. The Company estimates monthly revenue for a period based on wholesale electricity purchases because customer meters are not generally read at the end of each month. At the end of each month, the electricity delivered to customers, but not billed, is estimated and revenue is recognized. The unbilled revenue estimate is affected by energy demand, weather, line losses and changes in the composition of customer classes.

Distribution revenue also includes an amount relating to rate protection for rural, residential and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. Current legislation provides rate protection for prescribed classes of rural, residential and remote consumers by reducing the electricity rates that would otherwise apply.

Revenues also include amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are recorded at the invoiced amount or net realizable value, if unbilled. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Company's best estimate of losses on accounts receivable balances. The allowance is based on accounts receivable aging, historical experience and other currently available information. The Company estimates the allowance for doubtful accounts on customer receivables by applying internally developed loss rates to the outstanding receivable balances by risk segment. Risk segments represent groups of customers with similar credit quality indicators and are computed based on various attributes, including number of days receivables are past due, delinquency of balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average write-offs as a percentage of accounts receivable in each risk segment. An account is considered delinquent if the amount billed is not received within 120 days of the invoiced date. Accounts receivable are written off against the allowance when they are deemed uncollectible. The existing allowance for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions.

Corporate Income Taxes

Under the *Electricity Act, 1998*, Hydro One is required to make payments in lieu of corporate income taxes (PILs) to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) as modified by the *Electricity Act, 1998* and related regulations.

Current and deferred income taxes are computed based on the tax rates and tax laws enacted at the balance sheet date. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the "more-likely-than-not" recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgement is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Consolidated Financial Statements. Management re-evaluates tax positions each period in which new information about recognition or measurement becomes available.

Current Income Taxes

The provision for current taxes and the assets and liabilities recognized for the current and prior periods are measured at the amounts receivable from, or payable to, the OEFC.

Deferred Income Taxes

Deferred income taxes are provided for using the liability method. Deferred income taxes are recognized based on the estimated future tax consequences attributable to temporary differences between the carrying amount of assets and liabilities in the Consolidated Financial Statements and their corresponding tax bases.

Deferred income tax liabilities are generally recognized on all taxable temporary differences. Deferred tax assets are recognized to the extent that it is more-likely-than-not that these assets will be realized from taxable income available against which deductible temporary differences can be utilized.

Deferred income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates and tax laws that have been enacted at the balance sheet date. Deferred income taxes that are not included in the rate-setting process are charged or credited to the Consolidated Statements of Operations and Comprehensive Income.

If management determines that it is more-likely-than-not that some or all of a deferred income tax asset will not be realized, a valuation allowance is recorded against the tax asset to report the net balance at the amount expected to be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more-likely-than-not that the tax benefit will be realized.

The Company records regulatory assets and liabilities associated with deferred income taxes that will be included in the rate-setting process.

The Company uses the flow-through method to account for investment tax credits (ITCs) earned on eligible scientific research and experimental development expenditures, and apprenticeship job creation. Under this method, only the ITCs are recognized as a reduction to income tax expense.

Materials and Supplies

Materials and supplies represent consumables, small spare parts and construction materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions received in aid of construction and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the Consolidated Balance Sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of transmission, distribution, communication, administration and service assets and land easements. Property, plant and equipment also includes future use assets, such as land, major components and spare parts, and capitalized project development costs associated with deferred capital projects.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, including transformers, circuit breakers and switches.

Distribution

Distribution assets include assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include the fibre-optic and microwave radio system, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools and other minor assets.

Easements

Easements include statutory rights of use for transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other land access rights.

Intangible Assets

Intangible assets separately acquired or internally developed are measured on initial recognition at cost, which comprises purchased software, direct labour (including employee benefits), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Company's intangible assets primarily represent major administrative computer applications.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized portion of financing costs is a reduction to financing charges recognized in the Consolidated Statements of Operations and Comprehensive Income. Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation and Amortization

The cost of property, plant and equipment and intangible assets is depreciated or amortized on a straight-line basis based on the estimated remaining service life of each asset category, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically initiates an external independent review of its property, plant and equipment and intangible asset depreciation and amortization rates, as required by the OEB. Any changes arising from OEB approval of such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 2007.

A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average Service Life	Rate (%) Range	 Average
Transmission	56 years	1% - 3%	2%
Distribution	42 years	1% - 13%	2%
Communication	19 years	1% - 13%	5%
Administration and service	15 years	1% - 20%	8%

The cost of intangible assets is included primarily within the administration and service classification above. Amortization rates for computer applications software and other intangible assets range from 9% to 11%.

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, and intangible assets that are normally retired, is charged to accumulated depreciation, with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense. Depreciation expense also includes the costs incurred to remove property, plant and equipment where no ARO has been recorded.

Goodwill

Goodwill represents the cost of acquired local distribution companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is not included in rate base.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. Per Accounting Standards Update (ASU) 2011-08, Intangibles – Goodwill and Other (Topic 350), Testing Goodwill for Impairment, issued by the Financial Accounting Standards Board (FASB) in September 2011, the Company performs a qualitative assessment to determine whether it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount. If the Company determines, as a result of its qualitative assessment, that it is not more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, no further testing is required. If the Company determines, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, a goodwill impairment assessment is performed using a two-step, fair value-based test. The first step compares the fair value of the applicable reporting unit to its carrying amount, including goodwill. If the carrying amount of the applicable reporting unit exceeds its fair value, a second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and as a charge to results of operations.

For the year ended December 31, 2012, based on the qualitative assessment performed, the Company has determined that it is not more-likely-than-not that the fair value of each applicable reporting unit assessed is less than its carrying amount. As a result, no further testing was performed, and the Company has concluded that goodwill was not impaired at December 31, 2012.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, impairment exists when the carrying value exceeds the sum of the future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

Within its regulated business, the carrying costs of most of Hydro One's long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable.

Hydro One regularly monitors the assets of its unregulated Hydro One Telecom subsidiary for indications of impairment. Management assesses the fair value of such long-lived assets using commonly accepted techniques, and may use more than one. Techniques used to determine fair value include, but are not limited to, the use of recent third party comparable sales for reference and internally developed discounted cash flow analysis. Significant changes in market conditions, changes to the condition of an asset, or a change in management's intent to utilize the asset are generally viewed by management as triggering events to reassess the cash flows related to these long-lived assets. As at December 31, 2012, no asset impairment had been recorded for assets within either the Company's regulated or unregulated businesses.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers the external transaction costs related to obtaining debt financing and presents such amounts as deferred debt costs on the Consolidated Balance Sheets. Deferred debt costs are amortized over the contractual life of the related debt on an effective-interest basis and the amortization is included within financing charges in the Consolidated Statements of Operations and Comprehensive Income. Transaction costs for items classified as held-for-trading are expensed immediately.

Comprehensive Income

Comprehensive income is comprised of net income and other comprehensive income (OCI). OCI includes the amortization of net unamortized hedging losses on the Company's discounted cash flow hedges, and the change in fair value on the existing cash flow hedges to the extent that the hedge is effective. The Company amortizes its unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective-interest method over the term of the allocated hedged debt. Hydro One presents net income and OCI in a single continuous Consolidated Statement of Operations and Comprehensive Income.

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable and amounts due from related parties, which are measured at the lower of cost or fair value. Accounts receivable and amounts due from related parties are classified as loans and receivables. The Company considers the carrying amounts of accounts receivable and amounts due from related parties to be reasonable estimates of fair value because of the short time to maturity of these instruments. Provisions for impaired accounts receivable are recognized as adjustments to the allowance for doubtful accounts and are recognized when there is objective evidence that the Company will not be able to collect amounts according to the original terms.

Derivative instruments are measured at fair value. Gains and losses from fair valuation are included within financing charges in the period in which they arise. The Company determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Company's risk management policy disclosed in Note 12 – Fair Value of Financial Instruments and Risk Management.

Short-term investments have an original maturity of three months or less and are generally classified as held-to-maturity. However, the Company may classify pools of short-term investments as held-for-trading where there is no intention to hold a pool of assets to maturity. Documentation of the short-term investment classification is made on inception. As at December 31, 2012 and 2011, all short-term investments were classified as held-to-maturity.

The Company's long-term investment in Province of Ontario Floating-Rate Notes, which is held as an alternate form of liquidity to supplement the bank credit facilities, is classified as held-for-trading and is measured at fair value.

All financial instrument transactions are recorded at trade date.

Derivative Instruments and Hedge Accounting

The Company closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts) as they are part of economic hedging relationships.

The accounting guidance for derivative instruments requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value on the Consolidated Balance Sheets. For derivative instruments that qualify for hedge accounting, the Company may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. The Company offsets fair value amounts recognized in its Consolidated Balance Sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

For derivative instruments that qualify for hedge accounting and which are designated as cash flow hedges, the effective portion of any gain or loss, net of tax, is reported as a component of accumulated OCI (AOCI) and is reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations. Any gains or losses on the derivative instrument that represent either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in results of operations. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the Consolidated Statement of Operations and Comprehensive Income in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the Consolidated Statements of Operations and Comprehensive Income. Additionally, the Company enters into derivative agreements that are economic hedges that either do not qualify for hedge accounting or have not been designated as hedges. The changes in fair value of these undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and carried at fair value on the Consolidated Balance Sheets when: (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract; (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period; and (c) the embedded derivative itself meets the definition of a derivative. The Company does not engage in derivative trading or speculative activities and had no embedded derivatives at December 31, 2012.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where the Company has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. The Company also assesses, both at the inception of the hedge and on a quarterly basis, whether the hedging instruments are effective in offsetting changes in fair values or cash flows of the hedged items.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of the Company's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

The Company recognizes the funded status of its pension, post-retirement and post-employment plans on its Consolidated Balance Sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized in the Consolidated Balance Sheets for any net underfunded projected benefit obligation. The net underfunded projected benefit obligation may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the projected benefit obligation of the plan, an asset is recognized equal to the net overfunded projected benefit obligation. The net asset for an overfunded plan is classified as a long-term asset in the Consolidated Balance Sheets. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Pension benefits

Hydro One records a regulatory asset equal to the net underfunded projected benefit obligation for its pension plan. The regulatory asset for the net underfunded projected benefit obligation for the pension plan, in the absence of regulatory accounting, would be recognized in AOCI. A regulatory asset is recognized because management considers it to be probable that pension benefit costs will be recovered in the future through the rate-setting process. The pension regulatory assets are remeasured at the end of each year based on the current status of the pension plan.

In accordance with the OEB's rate orders, pension costs are recorded on a cash basis as employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Pension costs are also calculated on an accrual basis for financial reporting purposes. Pension costs are actuarially determined using the projected benefit method prorated on service and are based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases. Past service costs from plan amendments and all actuarial gains and losses are amortized on a straight-line basis over the expected average remaining service period of active employees in the plan, and over the estimated remaining life expectancy of inactive employees in the plan. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are fair valued at the end of each year.

All future pension benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

Post-retirement and post-employment benefits

Hydro One records a regulatory asset equal to the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans recorded on transition to US GAAP and at each year end based on annual actuarial reports. The regulatory asset for the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans, in the absence of regulatory accounting, would be recognized in AOCI. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active employees in the plan and over the remaining life expectancy of inactive employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the associated regulatory liabilities representing actuarial gains on transition to US GAAP are amortized to results of operations based on the "corridor" approach. Post transition, the actuarial gains and losses on post-employment obligations that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment future benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

Multiemployer Pension Plan

Employees of Hydro One Brampton Networks participate in the Ontario Municipal Employees Retirement System Fund (OMERS), a multiemployer, contributory, defined benefit public sector pension fund. OMERS provides retirement pension payments based on members' length of service and salary. Both participating employers and members are required to make plan contributions. The OMERS plan assets are pooled together to provide benefits to all plan participants and the plan assets are not segregated by member entity. OMERS is registered with the Financial Services Commission of Ontario under Registration #0345983.

The OMERS plan is accounted for as a defined contribution plan by Hydro One because it is not practicable to determine the present value of the Company's obligation, the fair value of plan assets or the related current service cost applicable to Hydro One Brampton Networks' employees. Hydro One recognizes its contributions to the OMERS plan as pension expense, with a portion being capitalized. The expensed amount is included in operation, maintenance and administration costs in the Consolidated Statements of Operations and Comprehensive Income.

At December 31, 2011, OMERS had approximately 419,000 members, with approximately 277 members being current employees of Hydro One Brampton Networks.

Loss Contingencies

Hydro One is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its Consolidated Financial Statements, management makes judgements regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Company records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgements about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Consolidated Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. Hydro One records a liability for the estimated future expenditures associated with the contaminated land assessment and remediation (LAR) and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate equal to its credit-adjusted risk-free interest rate on financial instruments with comparable maturities to the pattern of future environmental expenditures. As the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the future recovery of these environmental expenditures from customers. Hydro One reviews its estimates of future environmental expenditures annually, or more frequently if there are indications that circumstances have changed.

Asset Retirement Obligations

AROs are recorded for legal obligations associated with the future removal and disposal of long-lived assets. Such obligations may result from the acquisition, construction, development and/or normal use of the asset. Conditional AROs are recorded when there is a legal obligation to perform a future asset retirement activity but where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. In such a case, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement.

When recording an ARO, the present value of the estimated future expenditures required to complete the asset retirement activity is recorded in the period in which the obligation is incurred, if a reasonable estimate can be made. In general, the present value of the estimated future expenditures is added to the carrying amount of the associated asset and the resulting asset retirement cost is depreciated over the estimated useful life of the asset. Where an asset is no longer in service when an ARO is recorded, the asset retirement cost is recorded in results of operations.

Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have AROs, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its facilities in perpetuity, no ARO currently exists for these assets. If, at some future date, a particular facility is shown not to meet the perpetuity assumption, it will be reviewed to determine whether an estimable ARO exists. In such a case, an ARO would be recorded at that time.

The Company's AROs recorded to date relate to estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities and with the decommissioning of specific switching stations located on unowned sites.

3. NEW ACCOUNTING PRONOUNCEMENTS

Recently Adopted Accounting Pronouncements

In September 2011, the FASB issued ASU 2011-09, Disclosures About an Employer's Participation in a Multiemployer Benefit Plan. This ASU requires an employer to provide quantitative and qualitative disclosures about its participation in significant multiemployer plans that offer pension, post-retirement and post-employment benefits. The ASU's objective is to enhance the transparency of disclosures about the significant multiemployer plans in which an employer participates, the level of the employer's participation in those plans, the financial health of the plans, and the nature of the employer's commitments to the plans. An employer that is not able to provide some of the quantitative information required by this ASU must disclose what information has been omitted and why it could not obtain the information. This ASU does not change the recognition and measurement guidance for an employer's participation in a multiemployer plan. As this ASU only requires enhanced disclosures, the adoption of this ASU did not have a significant impact on the Company's Consolidated Financial Statements.

In September 2011, the FASB issued ASU 2011-08, Intangibles – Goodwill and Other (Topic 350), Testing Goodwill for Impairment. This ASU is intended to reduce the cost and complexity of the annual goodwill impairment test by providing entities an option to perform a qualitative assessment to determine whether further impairment testing is necessary. An entity has the option to first assess qualitative factors to determine whether it is necessary to perform the current two-step test. If an entity believes, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of a reporting unit is less than its carrying amount, the quantitative impairment test is required. Otherwise, no further testing is required. An entity can choose to perform the qualitative assessment on none, some or all of its reporting units. Moreover, an entity can bypass the qualitative assessment for any reporting unit in any period and proceed directly to step one of the impairment test, and then resume performing the qualitative assessment in any subsequent period. The adoption of this ASU did not have a significant impact on the Company's Consolidated Financial Statements.

In June 2011, the FASB issued ASU 2011-05, Presentation of Comprehensive Income to clarify that an entity has the option to present the total of comprehensive income, the components of net income, and the components of OCI either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In both choices, an entity is required to present each component of net income along with total net income, each component of OCI along with a total for OCI, and a total amount for comprehensive income. This update eliminates the option to present the components of OCI as part of the statement of changes in shareholder's equity. The amendments in this ASU do not change the items that must be reported in OCI or when an item of OCI must be reclassified to net income. Hydro One has elected to present OCI and net income in a single continuous Consolidated Statement of Operations and Comprehensive Income.

In May 2011, the FASB issued ASU 2011-04, Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs. This ASU is the result of joint efforts by the FASB and the International Accounting Standards Board to develop common, converged fair value guidance on how to measure fair value and on what disclosures to provide about fair value measurements. This ASU is largely consistent with existing US GAAP fair value measurement principles under Accounting Standards Codification 820. However, this ASU expands the existing disclosure requirements for fair value measurements, particularly of Level 3 inputs, and requires categorization by level of the fair value hierarchy for items that are not measured at fair value on the Consolidated Balance Sheets but for which the fair value is required to be disclosed. Required disclosures have been included in Note 12 – Fair Value of Financial Instruments and Risk Management. As this ASU only requires enhanced disclosures, the adoption of this ASU did not have a significant impact on the Company's Consolidated Financial Statements.

Recent Accounting Guidance Not Yet Adopted

In December 2011, the FASB issued ASU 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities. This ASU requires an entity to disclose both gross and net information about financial instruments and transactions eligible for offset on the Consolidated Balance Sheets as well as financial instruments and transactions executed under a master netting or similar arrangement. The ASU was issued to enable users of financial statements to understand the effects or potential effects of those arrangements on an entity's financial position. This ASU is required to be applied retrospectively and is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013. As this ASU only requires enhanced disclosures, the adoption of this ASU is not anticipated to have a significant impact on the Company's Consolidated Financial Statements.

4. DEPRECIATION AND AMORTIZATION

Year ended December 31 (millions of dollars)	**2012**	**2011**
Depreciation of property, plant and equipment	522	485
Amortization of intangible assets	48	45
Asset removal costs	70	66
Amortization of regulatory assets	19	20
	659	616

5. FINANCING CHARGES

Year ended December 31 (millions of dollars)	**2012**	**2011**
Interest on long-term debt	421	412
Other	12	5
Less: Interest capitalized on construction and development in progress	(59)	(58)
Gain on interest-rate swap agreements	(12)	(12)
Interest earned on investments	(4)	(3)
	358	344

6. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The major components of income tax expense are as follows:

Year ended December 31 (millions of dollars)	**2012**	**2011**
Current provision for PILs	130	162
Deferred recovery of PILs	(9)	(12)
Provision for PILs	121	150

The provision for PILs differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 (millions of dollars)	**2012**	**2011**
Income before provision for PILs	866	791
Canadian Federal and Ontario statutory income tax rate	26.50%	28.25%
Provision for PILs at statutory rate	230	223
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(42)	(34)
Pension contributions in excess of pension expense	(23)	(17)
Interest capitalized for accounting but deducted for tax purposes	(15)	(16)
Overheads capitalized for accounting but deducted for tax purposes	(14)	(12)
Non-refundable investment tax credits	(8)	-
Environmental expenditures	(5)	(4)
Post-retirement and post-employment benefit expense in excess of cash payments	-	5
Other	(3)	3
Net temporary differences	(110)	(75)
Net permanent differences	1	2
Total provision for PILs	121	150
Current provision for PILs	130	162
Deferred recovery of PILs	(9)	(12)
Total provision for PILs	121	150
Effective income tax rate	13.96%	18.96%

The current provision for PILs of $130 million represents the amount paid or payable to the OEFC with respect to current year income. The outstanding balance due to the OEFC at December 31, 2012 was $10 million (2011 – $85 million).

The total provision for PILs includes deferred recovery of PILs of $9 million that is not included in the rate-setting process, using the balance sheet liability method of accounting. Deferred PILs balances expected to be included in the rate-setting process are offset by regulatory assets and liabilities to reflect the anticipated recovery or disposition of these balances within future electricity rates.

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities arise from differences between the carrying amounts and tax bases of the Company's assets and liabilities. At December 31, deferred income tax assets and liabilities consisted of the following:

December 31 (millions of dollars)	**2012**	**2011**
Deferred income tax assets		
Depreciation and amortization in excess of capital cost allowance	3	6
Post-retirement and post-employment benefits expense in excess of cash payments	7	5
Environmental expenditures	4	5
Other	-	1
Total deferred income tax assets	14	17
Less: current portion	-	-
	14	17

December 31 (millions of dollars)	**2012**	**2011**
Deferred income tax liabilities		
Capital cost allowance in excess of depreciation and amortization	(1,344)	(1,106)
Post-retirement and post-employment benefits expense in excess of cash payments	519	356
Environmental expenditures	62	61
Regulatory amounts receivable that are not recognized for tax purposes	(147)	(36)
Goodwill	(19)	(18)
Other	3	4
Total deferred income tax liabilities	(926)	(739)
Less: current portion	18	19
	(944)	(758)

During 2012, the deferred tax liability increased by $60 million as a result of the change in the rate applicable to future taxes. At December 31, 2012, unused tax losses carried forward were less than $1 million (2011 – less than $1 million).

7. ACCOUNTS RECEIVABLE

December 31 (millions of dollars)	**2012**	**2011**
Accounts receivable – billed	224	235
Accounts receivable – unbilled	644	588
Accounts receivable, gross	868	823
Allowance for doubtful accounts	(23)	(18)
Accounts receivable, net	845	805

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2012 and 2011.

Year ended December 31 (millions of dollars)	**2012**	**2011**
Allowance for doubtful accounts – January 1	(18)	(25)
Write-offs	17	30
Additions to allowance for doubtful accounts	(22)	(23)
Allowance for doubtful accounts – December 31	(23)	(18)

8. PROPERTY, PLANT AND EQUIPMENT

December 31 (millions of dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
2012				
Transmission	11,840	3,990	641	8,491
Distribution	8,005	2,879	234	5,360
Communication	1,024	516	57	565
Administration and Service	1,314	668	123	769
Easements	614	92	-	522
	22,797	8,145	1,055	15,707
2011				
Transmission	10,906	3,810	1,079	8,175
Distribution	7,596	2,706	253	5,143
Communication	919	468	43	494
Administration and Service	1,232	607	61	686
Easements	493	88	-	405
	21,146	7,679	1,436	14,903

Financing charges capitalized on property, plant and equipment under construction were $56 million in 2012 (2011 – $57 million).

9. INTANGIBLE ASSETS

December 31 (millions of dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
2012				
Computer applications software	451	301	116	266
Other	5	4	-	1
	456	305	116	267
2011				
Computer applications software	427	254	49	222
Other	5	3	-	2
	432	257	49	224

Financing charges capitalized on intangible assets under development were $3 million in 2012 (2011 – $1 million). The estimated annual amortization expense for intangible assets for each of the next five years is $42 million.

10. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One has recorded the following regulatory assets and liabilities:

December 31 (millions of dollars)	2012	2011
Regulatory assets:		
Pension benefit regulatory asset	1,515	779
Deferred income tax regulatory asset	954	763
Post-retirement and post-employment benefits	320	123
Environmental	249	257
Pension cost variance	61	42
Rider 2	10	11
Long-term project development costs	5	5
Other	13	10
Total regulatory assets	3,127	1,990
Less: current portion	29	24
	3,098	1,966
Regulatory liabilities:		
External revenue variance	61	39
Retail settlement variance accounts	54	39
Rider 8	45	41
Deferred income tax regulatory liability	16	25
PST savings deferral	13	8
Rider 3	9	9
Rural and remote rate protection variance	6	8
Hydro One Brampton Networks rider	-	2
Other	17	23
Total regulatory liabilities	221	194
Less: current portion	40	25
	181	169

Pension Benefit Regulatory Asset

The Company recognizes the net unfunded status of pension obligations on the Consolidated Balance Sheets with an offset to the associated regulatory asset. A regulatory asset is recognized because management considers it to be probable that pension benefit costs will be recovered in the future through the rate-setting process. The pension benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2012 OCI would have been lower by $736 million (2011 – higher by $482 million).

Deferred Income Tax Regulatory Asset and Liability

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit. The Company has recognized regulatory assets and liabilities that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Company's provision for PILs would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, the 2012 provision for PILs would have been higher by approximately $136 million (2011 – $70 million), including the impact of a change in enacted tax rates.

Post-Retirement and Post-Employment Benefits

The Company recognizes the net unfunded status of post-retirement and post-employment obligations on the Consolidated Balance Sheets with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2012 OCI would have been lower by $197 million (2011 – higher by $30 million).

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate past environmental contamination (see Note 15 – Environmental Liabilities). Because such expenditures are expected to be recoverable in future rates, the Company has recorded an equivalent amount as a regulatory asset. In 2012, this regulatory asset decreased by $3 million (2011 – $55 million) to reflect related changes in the Company's PCB liability, and increased by $2 million (2011 – $5 million) due to changes in the LAR liability. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of Hydro One's actual environmental expenditures. In the absence of rate-regulated accounting, 2012 operation, maintenance and administration expenses would have been lower by $1 million (2011 – $50 million). In addition, 2012 amortization expense would have been lower by $18 million (2011 – $16 million), and 2012 financing charges would have been higher by $11 million (2011 – $14 million).

Pension Cost Variance

A pension cost variance account was established for each of Hydro One Networks' Transmission and Distribution businesses to track the difference between the actual pension expense incurred and estimated pension costs approved by the OEB. The balance in this account reflects the excess of pension costs paid as compared to OEB-approved amounts. In December 2010, the OEB approved the December 31, 2009 balance, including accrued interest, to be recovered over a one-year period from January 1, 2011 to December 31, 2011. In the absence of rate-regulated accounting, 2012 revenue would have been lower by $18 million (2011 – $14 million).

Rider 2

In April 2006, the OEB announced its decision regarding the Company's rate application in respect of the Distribution Business of Hydro One Networks. As part of this decision, the OEB also approved the distribution-related deferral account balances sought by Hydro One. The Rider 2 regulatory asset includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest.

Long-Term Project Development Costs

In May 2009, the OEB approved the creation of a deferral account to record Hydro One Networks' costs of preliminary work to advance certain transmission projects identified in the Company's 2009 and 2010 transmission rate applications. In March 2010, the OEB issued a decision amending the scope of the account to include the 20 major transmission projects identified in the September 2009 request from the Ministry of Energy and Infrastructure. In December 2010, the OEB approved the recovery of the December 31, 2009 balance, including accrued interest, to be recovered over a one-year period from January 1, 2011 to December 31, 2011. In the absence of rate-regulated accounting, 2011 operation, maintenance and administration expenses would have been lower by $2 million.

External Revenue Variance

In May 2009, the OEB approved forecasted amounts related to export service revenue, external revenue from secondary land use, and external revenue from station maintenance and engineering and construction work. These revenue sources are taken into account in structuring the Company's revenue requirement and as such, the OEB requested the establishment of new variance accounts to capture any difference between the approved forecasted external revenue amounts used in establishing the revenue requirement and actual external revenues. The external revenue variance account balance reflects the excess of actual external revenue compared to the OEB-approved forecasted amounts. In December 2010, the OEB approved the disposition of the December 31, 2009 balance, including accrued interest, to be disposed over a one-year period from January 1, 2011 to December 31, 2011.

Retail Settlement Variance Accounts (RSVAs)

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. In April 2010, the OEB approved the disposition of the total RSVA balance accumulated from May 2008 to December 2009, including accrued interest, to be disposed over a 20-month period from May 1, 2010 to December 31, 2011. Hydro One has continued to accumulate a net liability in its RSVA accounts since December 31, 2009.

Rider 8

In April 2010, the OEB requested the establishment of deferral accounts which capture the difference between the revenue recorded on the basis of Green Energy Plan expenditures incurred and the actual recoveries received.

PST Savings Deferral Account

The provincial sales tax (PST) and goods and services tax (GST) were harmonized in July 2010. Unlike the GST, the PST was included in operation, maintenance and administrative expenses or capital expenditures for past revenue requirements approved during a full cost of service hearing. Under the harmonized sales tax (HST) regime, the HST included in operation, maintenance and administrative expenses or capital expenditures is not a cost ultimately borne by the Company and as such, a refund of the prior PST element in the approved revenue requirement is applicable and calculations for tracking and refund were requested by the OEB. For the Hydro One Networks Transmission revenue requirement, PST was included between July 1, 2010 and December 31, 2010 and recorded in a deferral account per direction from the OEB. For the Hydro One Networks Distribution revenue requirement, PST was included between July 1, 2010 and December 31, 2012 and recorded in a deferral account per direction from the OEB.

Rider 3

In December 2008, the OEB approved certain distribution-related deferral account balances sought by Hydro One, including RSVA amounts, deferred tax changes, OEB costs and smart meters. The OEB approved the disposition of the Rider 3 balance accumulated up to April 2008, including accrued interest, to be disposed over a 27-month period from February 1, 2009 to April 30, 2011.

Rural and Remote Rate Protection Variance (RRRP)

Hydro One receives rural rate protection amounts from the IESO. A portion of these amounts is provided to retail customers of Hydro One Networks who are eligible for rate protection. The OEB has approved a mechanism to collect the RRRP through the Wholesale Market Service Charge. Variances between the amounts remitted by the IESO to Hydro One and the fixed entitlements defined in the regulation, and subsequent OEB utility rate decisions, are tracked by the Company in the RRRP variance account.

Hydro One Brampton Networks Rider

In April 2010, the OEB issued a decision regarding the 2010 distribution rates of Hydro One Brampton Networks. Included in the OEB's decision was the approval of certain deferral account balances, primarily RSVAs, sought by Hydro One Brampton Networks in its application. The OEB ordered that the approved balances be aggregated into a single regulatory account and disposed of through a rate rider over a two-year period from May 1, 2010 to April 30, 2012.

11. DEBT AND CREDIT AGREEMENTS

Short-Term Notes

Hydro One meets its short-term liquidity requirements in part through the issuance of commercial paper under its Commercial Paper Program with a maximum amount of $1,000 million. These short-term notes are denominated in Canadian dollars with varying maturities not exceeding 365 days. Hydro One had no commercial paper borrowings outstanding as at December 31, 2012 and 2011.

The Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities comprised of a $1,250 million committed revolving standby credit facility with a syndicate of banks and a long-term investment in Province of Ontario Floating-Rate Notes with a fair value of $251 million at December 31, 2012.

Long-Term Debt

The Company issues notes for long-term financing under its Medium-Term Note (MTN) Program. The maximum authorized principal amount of notes issuable under this program is $3,000 million. At December 31, 2012, $1,515 million remained available until September 2013.

The following table presents the outstanding long-term debt at December 31, 2012 and 2011:

December 31 (millions of dollars)	**2012**	**2011**
5.77% Series 3 notes due 2012	-	600
5.00% Series 15 notes due 2013	600	600
3.13% Series 19 notes due 2014[1]	750	750
2.95% Series 21 notes due 2015[1]	500	500
Floating-rate Series 22 notes due 2015[2]	50	50
4.64% Series 10 notes due 2016	450	450
Floating-rate Series 27 notes due 2016[2]	50	-
5.18% Series 13 notes due 2017	600	600
4.40% Series 20 notes due 2020	300	300
3.20% Series 25 notes due 2022	600	-
7.35% debentures due 2030	400	400
6.93% Series 2 notes due 2032	500	500
6.35% Series 4 notes due 2034	385	385
5.36% Series 9 notes due 2036	600	600
4.89% Series 12 notes due 2037	400	400
6.03% Series 17 notes due 2039	300	300
5.49% Series 18 notes due 2040	500	500
4.39% Series 23 notes due 2041	300	300
6.59% Series 5 notes due 2043	315	315
5.00% Series 11 notes due 2046	325	325
4.00% Series 24 notes due 2051	225	100
3.79% Series 26 notes due 2062	310	-
	8,460	7,975
Add: Unrealized marked-to-market loss[1]	19	33
Less: Long-term debt payable within one year	(600)	(600)
Long-term debt	7,879	7,408

[1] The unrealized marked-to-market loss relates to $500 million of the Series 19 notes due 2014, and $250 million of the Series 21 notes due 2015. The unrealized marked-to-market loss is offset by a $19 million (2011 – $33 million) unrealized marked-to-market gain on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges. See Note 12 – Fair Value of Financial Instruments and Risk Management for details of fair value hedges.

[2] The interest rates of the floating-rate notes are referenced to the 3-month Canadian dollar bankers' acceptance rate, plus a margin.

In 2012, Hydro One issued $1,085 million of long-term debt under the MTN Program, consisting of $300 million issued in the first quarter, $425 million issued in the second quarter, $310 million issued in the third quarter, and $50 million issued in the fourth quarter of 2012. In September 2012, the Company also redeemed the $600 million MTN Series 3 notes.

The long-term debt is unsecured and denominated in Canadian dollars. The long-term debt is summarized by the number of years to maturity in Note 12 – Fair Value of Financial Instruments and Risk Management.

Credit Agreements

Hydro One has a $1,250 million committed and unused revolving standby credit facility with a syndicate of banks, maturing in June 2017. If used, interest on the facility would apply based on Canadian benchmark rates. This credit facility supports the Company's Commercial Paper Program.

The Company may use the credit facility for general corporate purposes, including meeting short-term funding requirements. The obligation of each lender to make any credit extension to the Company under its credit facility is subject to various conditions including, among other things, that no event of default has occurred or would result from such credit extension.

12. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

Hydro One classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non-Derivative Financial Assets and Liabilities

At December 31, 2012 and 2011, the Company's carrying amounts of accounts receivable, due from related parties, short-term investments, bank indebtedness, accounts payable, accrued liabilities, and due to related parties are representative of fair value because of the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Company's long-term debt at December 31, 2012 and 2011 are as follows:

December 31 (millions of dollars)	2012 Carrying Value	2012 Fair Value	2011 Carrying Value	2011 Fair Value
Long-term debt				
$500 million of MTN Series 19 notes[1]	512	512	521	521
$250 million of MTN Series 21 notes[2]	257	257	262	262
Other notes and debentures[3]	7,710	9,188	7,225	8,615
	8,479	9,957	8,008	9,398

[1] The fair value of $500 million of the MTN Series 19 notes subject to hedging is primarily based on changes in the present value of future cash flows due to a change in the yield in the swap market for the related swap (hedged risk).

[2] The fair value of $250 million of the MTN Series 21 notes subject to hedging is primarily based on changes in the present value of future cash flows due to a change in the yield in the swap market for the related swap (hedged risk).

[3] The fair value of other notes and debentures, and the portions of the MTN Series 19 notes and the MTN Series 21 notes that are not subject to hedging, represents the market value of the notes and debentures and is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

Fair Value Measurements of Derivative Instruments

At December 31, 2012, the Company had interest-rate swaps totaling $750 million (2011 – $750 million) that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. The Company's fair value hedge exposure was equal to about 9% (2011 – 9%) of its total long-term debt of $8,479 million (2011 – $8,008 million). At December 31, 2102, the Company had the following interest-rate swaps designated as fair value hedges:

(a) two $250 million fixed-to-floating interest-rate swap agreements to convert $500 million of the $750 million MTN Series 19 notes maturing November 19, 2014 into three-month variable rate debt; and

(b) two $125 million fixed-to-floating interest-rate swap agreements to convert $250 million of the $500 million MTN Series 21 notes maturing September 11, 2015 into three-month variable rate debt.

At December 31, 2012, the Company also had interest-rate swaps with a total notional value of $900 million classified as undesignated contracts. The undesignated contracts consist of the following interest-rate swaps:

(c) three $250 million floating-to-fixed interest-rate swap agreements that lock in the floating rate the Company pays on a portion of the above fixed-to-floating interest-rate swaps from December 11, 2012 to December 11, 2013, from February 21, 2012 to February 19, 2013, and from February 19, 2013 to February 19, 2014, respectively;

(d) two $50 million floating-to-fixed interest-rate swap agreements that lock in the floating rate the Company pays on the $50 million floating-rate MTN Series 22 notes from January 24, 2012 to January 24, 2013, and from January 24, 2013 to January 24, 2014; and

(e) a $50 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on the $50 million floating-rate MTN Series 27 notes from March 4, 2013 to December 3, 2013.

At December 31, 2012 and 2011, the Company's carrying amounts of derivative instruments were representative of fair value.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2012 and 2011 is as follows:

December 31, 2012 (millions of dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Short-term investments	195	195	-	195	-
Long-term investment	251	251	-	251	-
Derivative instruments					
Fair value hedges – interest-rate swaps	19	19	-	19	-
	465	465	-	465	-
Liabilities:					
Bank indebtedness	42	42	42	-	-
Long-term debt	8,479	9,957	-	9,957	-
	8,521	9,999	42	9,957	-

December 31, 2011 (millions of dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Short-term investments	228	228	-	228	-
Long-term investment	250	250	-	250	-
Derivative instruments					
Fair value hedges – interest-rate swaps	33	33	-	33	-
Undesignated contracts – interest-rate swaps	1	1	-	1	-
	512	512	-	512	-
Liabilities:					
Bank indebtedness	39	39	39	-	-
Long-term debt	8,008	9,398	-	9,398	-
	8,047	9,437	39	9,398	-

The short-term investments represent investments with an original maturity of three months or less. The fair value of the short-term investments is determined using inputs other than quoted prices that are observable for the assets. The Company obtains quotes for the fair value of the short-term investments from an independent third party.

The long-term investment represents the Province of Ontario Floating-Rate Notes. The fair value of the long-term investment is determined using inputs other than quoted prices that are observable for the asset, with unrecognized gains or losses recognized in financing charges. The Company obtains quotes from an independent third party for the fair value of the long-term investment, who uses the market price of similar securities adjusted for changes in observable inputs such as maturity dates and interest rates.

The fair value of the derivative instruments is determined using other than quoted prices that are observable for these assets. The fair value is primarily based on the present value of future cash flows using a swap yield curve to determine the assumptions for interest rates.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no significant transfers between any of the levels during the years ended December 31, 2012 and 2011.

See Note 14 – Pension and Post-Retirement and Post-Employment Benefits for further information regarding the fair value and related valuation techniques for pension plan assets.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. The Company does not have commodity risk. The Company does have foreign exchange risk as it enters into agreements to purchase materials and equipment associated with capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material, although the Company could in the future decide to issue foreign currency-denominated debt which would be hedged back to Canadian dollars consistent with its risk management policy. Hydro One is exposed to fluctuations in interest rates as the regulated rate of return for the Company's transmission and distribution businesses is derived using a formulaic approach that is based on the forecast for long-term Government of Canada bond yields and the spread in 30-year "A"-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield. The Company estimates that a 1% decrease in the forecasted long-term Government of Canada bond yield or the "A"-rated Canadian utility spread used in determining the Company's rate of return would reduce the Transmission Business' results of operations by approximately $18 million (2011 – $18 million) and Hydro One Networks' Distribution Business' results of operations by approximately $10 million (2011 – $10 million).

The Company uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. The Company also uses derivative financial instruments to manage interest-rate risk. The Company utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. In addition, the Company may utilize interest-rate derivative instruments to lock in interest rate levels in anticipation of future financing. Hydro One may also enter into derivative agreements such as forward-starting pay fixed-interest-rate swap agreements to hedge against the effect of future interest rate movements on long-term fixed-rate borrowing requirements. Such arrangements are typically designated as cash flow hedges. No cash flow hedge agreements were outstanding as at December 31, 2012 or 2011.

A hypothetical 10% increase in the interest rates associated with variable-rate debt would not have resulted in a significant decrease in Hydro One's results of operations for the years ended December 31, 2012 or 2011.

Fair Value Hedges

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Consolidated Statements of Operations and Comprehensive Income. The net unrealized loss (gain) on the hedged debt and the related interest rate swaps for the years ended December 31, 2012 and 2011 are included in financing charges as follows:

Year ended December 31 (millions of dollars)	**2012**	**2011**
Unrealized loss (gain) on hedged debt	(14)	25
Unrealized loss (gain) on fair value interest-rate swaps	14	(25)
Net unrealized loss (gain)	-	-

At December 31, 2012, Hydro One had $750 million (2011 – $750 million) of notional amounts of fair value hedges outstanding related to interest-rate swaps, with assets at fair value of $19 million (2011 – $33 million). During the years ended December 31, 2012 and 2011, there was no significant impact on the results of operations as a result of any ineffectiveness attributable to fair value hedges.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2012 and 2011, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a significant amount of revenue from any individual customer. At December 31, 2012 and 2011, there was no significant accounts receivable balance due from any single customer.

At December 31, 2012, the Company's provision for bad debts was $23 million (2011 – $18 million). Adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2012, approximately 3% of the Company's accounts receivable were aged more than 60 days (2011 – 3%).

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly-rated counterparties; limiting total exposure levels with individual counterparties consistent with the Company's Board-approved Credit Risk Policy; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. In addition to payment netting language in master agreements, the Company establishes credit limits, margining thresholds and collateral requirements for each counterparty. Counterparty credit limits are based on an internal credit review that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings and risk management capabilities. The determination of credit exposure for a particular counterparty is the sum of current exposure plus the potential future exposure with that counterparty. The current exposure is calculated as the sum of the principal value of money market exposures and the market value of all contracts that have a positive mark-to-market position on the measurement date. The Company would only offset the positive market values against negative values with the same counterparty where permitted by the existence of a legal netting agreement such as an International Swap Dealers Association master agreement. The potential future exposure represents a safety margin to protect against future fluctuations of interest rates, currencies, equities, and commodities. It is calculated based on factors developed by the Bank of International Settlements, following extensive historical analysis of random fluctuations of interest rates and currencies. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with the Company as specified in each agreement. The Company monitors current and forward credit exposure to counterparties both on an individual and an aggregate basis. The Company's credit risk for accounts receivable is limited to the carrying amounts on the Consolidated Balance Sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At December 31, 2012, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was $22 million (2011 – $36 million). At December 31, 2012, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with four financial institutions as the counterparties. The credit exposure of each of the four counterparties accounted for more than 10% of the total credit exposure.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One meets its short-term liquidity requirements using cash and cash equivalents on hand, funds from operations, the issuance of commercial paper, the revolving standby credit facility, and by holding Province of Ontario Floating-Rate Notes. The Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities comprised of a $1,250 million committed revolving credit facility with a syndicate of banks maturing in June 2017 and the Province of Ontario Floating-Rate Notes with a fair value of $251 million. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund normal operating requirements.

At December 31, 2012, accounts payable and accrued liabilities in the amount of $722 million are expected to be settled in cash at their carrying amounts within the next year.

At December 31, 2012, Hydro One had issued long-term debt in the notional amount of $8,460 million (2011 – $7,975 million). Long-term debt maturing during the next year is $600 million (2011 – $600 million). Interest payments for the next 12 months on the Company's outstanding long-term debt amount to $410 million (2011 – $408 million). Principal outstanding, interest payments and related weighted average interest rates are summarized by the number of years to maturity in the following table.

Years to Maturity	Principal Outstanding on Long-term Debt *(millions of dollars)*	Interest Payments[1] *(millions of dollars)*	Weighted Average Interest Rate[1] *(%)*
1 year	600	410	5.0
2 years	750	379	3.1
3 years	550	356	2.8
4 years	500	331	4.3
5 years	600	320	5.2
	3,000	1,796	4.1
6 – 10 years	900	1,403	3.6
Over 10 years	4,560	4,138	5.6
	8,460	7,337	4.9

[1] Interest payments and weighted average interest rates beyond 1 year exclude the impact of the $50 million floating-rate Series 22 notes due 2015 and the $50 million floating-rate Series 27 notes due 2016.

13. CAPITAL MANAGEMENT

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing effective access to capital, the Company targets to maintain an "A" category long-term credit rating.

The Company considers its capital structure to consist of shareholder's equity, preferred shares, long-term debt, and cash and cash equivalents. At December 31, 2012 and 2011, the Company's capital structure was as follows:

December 31 (millions of dollars)	**2012**	**2011**
Long-term debt payable within one year	600	600
Less: Cash and cash equivalents	195	228
	405	372
Long-term debt	7,879	7,408
Preferred shares	323	323
Common shares	3,314	3,314
Retained earnings	3,202	2,827
	6,516	6,141
Total capital	15,123	14,244

The Company has customary covenants typically associated with long-term debt. Among other things, Hydro One's long-term debt and credit facility covenants limit the permissible debt to 75% of the Company's total capitalization, limit the ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2012 and 2011, Hydro One was in compliance with all of these covenants and limitations.

14. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan, a supplementary pension plan, and post-retirement and post-employment benefit plans. The defined benefit pension plan (Pension Plan) is contributory and covers all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton Networks. Employees of Hydro One Brampton Networks participate in the OMERS plan, a multiemployer public sector pension fund. The supplementary pension plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan but for the limitations imposed by the *Income Tax Act* (Canada). The supplementary pension plan obligation is included with other post-retirement and post-employment benefit obligations on the Consolidated Balance Sheets.

The OMERS Plan

Hydro One contributions to the OMERS plan for the year ended December 31, 2012 were $2 million (2011 – $1 million). Company contributions payable at December 31, 2012 and included in accrued liabilities on the Consolidated Balance Sheets were $0.2 million (2011 – $0.2 million). Hydro One contributions do not represent more than 5% of total contributions to the OMERS plan, as indicated in OMERS's most recently available annual report for the year ended December 31, 2011.

At December 31, 2011, the OMERS plan was 88.7% funded, with an unfunded liability of $7,290 million. This unfunded liability will likely result in future payments by participating employers and members. Hydro One future contributions could be increased substantially if other entities withdraw from the plan.

Pension Plan, Post-Retirement and Post-Employment Plans

The Pension Plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for new Society of Energy Professionals-represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation.

Company and employees' contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Annual Pension Plan contributions for 2012 of $163 million (2011 – $152 million) were based on an actuarial valuation effective December 31, 2011 and the level of 2012 pensionable earnings. Estimated annual Pension Plan contributions for 2013 are $162 million, based on the December 31, 2011 valuation and the projected level of pensionable earnings.

Hydro One recognizes the overfunded or underfunded status of the Pension Plan, and post-retirement and post-employment plans (Plans) as an asset or liability on its Consolidated Balance Sheets, with offsetting regulatory assets and liabilities as appropriate. The underfunded benefit obligations for the Plans, in the absence of regulatory accounting, would be recognized in AOCI. The impact of changes in assumptions used to measure pension, post-retirement and post-employment benefit obligations is generally recognized over the expected average remaining service period of the employees. For the year ended December 31, 2012, the measurement date for the Plans was December 31.

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31 (millions of dollars)	**2012**	**2011**	**2012**	**2011**
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	5,461	4,996	1,206	1,178
Current service cost	123	108	29	30
Interest cost	285	286	63	68
Reciprocal transfers	1	4	-	-
Benefits paid	(291)	(289)	(42)	(42)
Net actuarial loss (gain)	928	356	203	(28)
Projected benefit obligation, end of year	6,507	5,461	1,459	1,206
Change in plan assets				
Fair value of plan assets, beginning of year	4,682	4,699	-	-
Actual return on plan assets	425	102	-	-
Reciprocal transfers	1	4	-	-
Benefits paid	(291)	(289)	-	-
Employer's contributions	163	153	-	-
Employees' contributions	27	27	-	-
Administrative expenses	(15)	(14)	-	-
Fair value of plan assets, end of year	4,992	4,682	-	-
Unfunded status	1,515	779	1,459	1,206

Hydro One presents its benefit obligations and plan assets net on its Consolidated Balance Sheets within the following line items:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
December 31 (millions of dollars)	**2012**	**2011**	**2012**	**2011**
Accrued liabilities	-	-	43	43
Pension benefit liability	1,515	779	-	-
Post-retirement and post-employment benefit liability	-	-	1,416	1,163
Unfunded status	1,515	779	1,459	1,206

The funded/unfunded status of the pension, post-retirement and post-employment benefit plans refers to the difference between the fair value of plan assets and the projected benefit obligations for the Plans. The funded/unfunded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets.

The following table provides the projected benefit obligation (PBO), accumulated benefit obligation (ABO) and fair value of plan assets for the Pension Plan.

December 31 (millions of dollars)	**2012**	**2011**
PBO	6,507	5,461
ABO	6,074	5,038
Fair value of plan assets	4,992	4,682

On an ABO basis, the plans were funded at 82% at December 31, 2012 (2011 – 93%). On a PBO basis, the plans were funded at 77% at December 31, 2012 (2011 – 86%). The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

Components of Net Periodic Benefit Costs

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2012 and 2011 for all plans:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31 (millions of dollars)	**2012**	**2011**	**2012**	**2011**
Current service cost, net of employee contributions	96	81	30	30
Interest cost	285	286	63	67
Expected return on plan assets net of expenses	(289)	(291)	-	-
Actuarial loss amortization	112	68	8	7
Prior service cost amortization	3	4	3	4
Net Periodic Benefit Cost	207	148	104	108
Charged to results of operations[1]	76	93	48	61

[1] The Company follows the cash basis of accounting consistent with the inclusion of pension costs in OEB-approved rates. During the year ended December 31, 2012, pension costs of $163 million (2011 – $153 million) were attributed to labour, of which $76 million (2011 – $93 million) was charged to operations and $87 million (2011 – $60 million) was capitalized as part of the cost of property, plant and equipment and intangible assets.

Assumptions

The measurement of the obligations of the Plans and costs of providing benefits under Plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, the Company considers historical information as well as future expectations. The measurement of benefit obligations and costs is impacted by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, Hydro One's expected level of contributions to the Plans, the incidence of mortality, the expected remaining service period of plan participants, the level of compensation and rate of compensation increases, employee age, length of service, and the anticipated rate of increase of health care costs, among other factors. The impact of changes in assumptions used to measure the obligations of the Plans is generally recognized over the expected average remaining service period of the plan participants. In selecting the expected rate of return on plan assets, Hydro One considers historical economic indicators (including inflation and GDP growth) that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by target asset class allocations. In general, equity securities, real estate and private equity investments are forecasted to have higher returns than fixed income securities.

The following weighted average assumptions were used to determine the benefit obligations and benefit expense at December 31, 2012 and 2011. Assumptions used to determine current year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31	**2012**	**2011**	**2012**	**2011**
Significant assumptions:				
For net periodic benefit cost, year ended December 31:				
Weighted average expected rate of return on plan assets	6.25%	6.25%	-	-
Weighted average discount rate	5.25%	5.75%	5.25%	5.75%
Rate of compensation scale escalation (without merit)	2.50%	2.50%	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%	2.00%	2.00%
Average remaining service life of employees *(years)*	11	11	11	11
Rate of increase in health care cost trends[1]	-	-	4.41%	4.91%
For projected benefit obligation, at December 31:				
Weighted average discount rate	4.25%	5.25%	4.25%	5.25%
Rate of compensation scale escalation (without merit)	2.50%	2.50%	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%	2.00%	2.00%
Rate of increase in health care cost trends[2]	-	-	4.39%	4.41%

[1] 7.03% per annum in 2012, grading down to 4.41% per annum in and after 2031 (2011 – 7.56% in 2011, grading down to 4.91% per annum in and after 2029)

[2] 6.91% per annum in 2013, grading down to 4.39% per annum in and after 2031 (2011 – 7.03% in 2012, grading down to 4.41% per annum in and after 2031)

The discount rate used to determine the current year pension obligation and the subsequent year's net periodic benefit costs is based on a yield curve approach. Under the yield curve approach, expected future benefit payments for each plan are discounted by a rate on a third party bond yield curve corresponding to each duration. The yield curve is based on AA long-term corporate bonds. A single discount rate is calculated that would yield the same present value as the sum of the discounted cash flows.

The effect of 1% change in health care cost trends on the post-retirement and post-employment benefits is as follows:

Year ended December 31 (millions of dollars)	**2012**	**2011**
Effect of 1% increase in health care cost trends on:		
Projected benefit obligation at December 31	246	174
Service cost and interest cost	17	20
Effect of 1% decrease in health care cost trends on:		
Projected benefit obligation at December 31	(191)	(138)
Service cost and interest cost	(13)	(14)

Estimated Future Benefit Payments

At December 31, 2012, estimated future benefit payments by the Company to Plan participants were:

(millions of dollars)	Pension Benefits	Post-Retirement and Post-Employment Benefits
2013	299	51
2014	306	54
2015	313	57
2016	318	61
2017	324	64
2018 through to 2022	1,690	374
Total estimated future benefit payments through to 2022	3,250	661

Components of Regulatory Assets

A portion of actuarial gains and losses and prior service costs is recorded within regulatory assets on Hydro One's Consolidated Balance Sheets to reflect the expected regulatory inclusion of these amounts in future rates, which would otherwise be recorded in OCI. The following table provides the actuarial gains and losses and prior service costs recorded within regulatory assets:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31 (millions of dollars)	**2012**	**2011**	**2012**	**2011**
Actuarial loss (gain) for the year	807	558	203	(27)
Actuarial loss amortization	(112)	(68)	(8)	(7)
Prior service cost amortization	(3)	(4)	(3)	(3)
	692	486	192	(37)

The following table provides the components of regulatory assets that have not been recognized as components of net periodic benefit costs for the years ended December 31, 2012 and 2011:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31 (millions of dollars)	**2012**	**2011**	**2012**	**2011**
Prior service cost	5	7	5	7
Actuarial loss	1,510	772	315	116
	1,515	779	320	123

The following table provides the components of regulatory assets at December 31 that are expected to be amortized as components of net periodic benefit costs in the following year:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31 (millions of dollars)	**2012**	**2011**	**2012**	**2011**
Prior service cost	2	3	3	3
Actuarial loss	175	112	17	4
	177	115	20	7

Pension Plan Assets

Investment Strategy

On a regular basis, Hydro One evaluates its investment strategy to ensure that plan assets will be sufficient to pay Pension Plan benefits when due. As part of this ongoing evaluation, Hydro One may make changes to its targeted asset allocation and investment strategy. The Pension Plan is managed at a net asset level. The main objective of the Pension Plan is to sustain a certain level of net assets in order to meet the pension obligations of the Company. The Pension Plan fulfills its primary objective by adhering to specific investment policies outlined in its Summary of Investment Policies and Procedures (SIPP), which is reviewed and approved by the Investment-Pension Committee of Hydro One's Board of Directors. The Company manages net assets by engaging knowledgeable external investment managers who are charged with the responsibility of investing existing funds and new funds (current year's employee and employer contributions) in accordance with the approved SIPP. The performance of the managers is monitored through a governance structure. Increases in net assets are a direct result of investment income generated by investments held by the Pension Plan and contributions to the Pension Plan by eligible employees and by the Company. The main use of net assets is for benefit payments to eligible Pension Plan members.

Pension Plan Asset Mix

At December 31, 2012, the Pension Plan target asset allocations and weighted average asset allocations were as follows:

December 31, 2012	Target Allocation (%)	Pension Plan Assets (%)
Equity securities	60.0	64.1
Debt securities	35.0	35.8
Other [1]	5.0	0.1
	100.0	100.0

[1] Other investments include real estate and infrastructure investments.

At December 31, 2012, the Pension Plan held $20 million of Hydro One corporate bonds (2011 – $27 million) and $243 million of debt securities of the Province (2011 – $214 million).

Concentrations of Credit Risk

Hydro One evaluated its Pension Plan's asset portfolio for the existence of significant concentrations of credit risk as at December 31, 2012 and 2011. Concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, concentrations in a type of industry, and concentrations in individual funds. At December 31, 2012 and 2011, there were no significant concentrations (defined as greater than 10% of plan assets) of risk in the Pension Plan's assets.

The Pension Plan manages its counterparty credit risk with respect to bonds by investing in investment-grade and government bonds and with respect to derivative instruments by transacting only with financial institutions rated at least "AA" by S&P or "Aa2" by Moody's Investors Service Inc. and also by utilizing exposure limits to each counterparty. The risk of default on transactions in listed securities is considered minimal, as the trade will fail if either party to the transaction does not meet its obligation.

Fair Value Measurements

The following table presents the Pension Plan assets measured and recorded at fair value on a recurring basis and their level within the fair value hierarchy at December 31, 2012 and 2011:

December 31, 2012 (millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Pooled funds	2	15	104	121
Cash and cash equivalents	125	-	-	125
Short-term securities	-	100	-	100
Real estate	-	-	2	2
Corporate shares – Canadian	920	-	-	920
Corporate shares – Foreign	2,077	-	-	2,077
Bonds and debentures – Canadian	-	1,643	-	1,643
Total fair value of plan assets[1]	3,124	1,758	106	4,988

[1] At December 31, 2012, the total fair value of Pension Plan assets excludes $16 million of interest and dividends receivable, $4 million relating to accruals for pending sales transactions and $8 million relating to accruals for pension administration expense.

December 31, 2011 (millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Pooled funds	3	15	165	183
Cash and cash equivalents	128	-	-	128
Short-term securities	-	38	-	38
Real estate	-	-	2	2
Corporate shares – Canadian	820	-	-	820
Corporate shares – Foreign	1,820	-	-	1,820
Bonds and debentures – Canadian	-	1,675	-	1,675
Bonds and debentures – Foreign	-	1	-	1
Total fair value of plan assets[1]	2,771	1,729	167	4,667

[1] At December 31, 2011, the total fair value of Pension Plan assets excludes $17 million of interest and dividends receivable, $8 million of receivables relating to pending sales transactions, and $10 million relating to accruals for pension administration expense.

See Note 12 – Fair Value of Financial Instruments and Risk Management for a description of levels within the fair value hierarchy.

Changes in the Fair Value of Financial Instruments Classified in Level 3

The following table summarizes the changes in fair value of financial instruments classified in Level 3 for the years ended December 31, 2012 and 2011. The Pension Plan classifies financial instruments as Level 3 when the fair value is measured based on at least one significant input that is not observable in the markets or due to lack of liquidity in certain markets. The gains and losses presented in the table below may include changes in fair value based on both observable and unobservable inputs.

Year ended December 31 (millions of dollars)	**2012**	**2011**
Fair value, beginning of year	167	167
Realized and unrealized gains	5	18
Purchases	6	9
Sales and disbursements	(72)	(27)
Fair value, end of year	106	167

There have been no material transfers into or out of Level 3 of the fair value hierarchy.

The Company performs sensitivity analysis for fair value measurements classified in Level 3, substituting the unobservable inputs with one or more reasonably possible alternative assumptions. These sensitivity analyses resulted in negligible changes in the fair value of financial instruments classified in this level.

Valuation Techniques Used to Determine Fair Value

Pooled Funds

The pooled fund category mainly consists of private equity investments. Private equity investments represent private equity funds that invest in operating companies that are not publicly traded on a stock exchange. Investment strategies in private equity include limited partnerships in businesses that are characterized by high internal growth and operational efficiencies, venture capital, leveraged buyouts and special situations such as distressed investments. Private equity valuations are reported by the fund manager and are based on the valuation of the underlying investments which includes inputs such as cost, operating results, discounted future cash flows and market-based comparable data. Since these valuation inputs are not highly observable, private equity investments have been categorized as Level 3 within pooled funds.

Cash Equivalents

Demand cash deposits held with banks and cash held by the investment managers are considered cash equivalents and are included in the fair value measurements hierarchy as Level 1.

Short-Term Securities

Short-term securities are valued at cost plus accrued interest, which approximates fair value due to their short-term nature. Short-term securities have been categorized as Level 2.

Real Estate

Real estate investments represent private equity investments in holding companies that invest in real estate properties. The investments in the holding companies are valued using net asset values reported by the fund manager. Real estate investments are categorized as Level 3.

Corporate Shares

Corporate shares are valued based on quoted prices in active markets and are categorized as Level 1. Investments denominated in foreign currencies are translated into Canadian currency at year-end rates of exchange.

Bonds and Debentures

Bonds and debentures are presented at published closing trade quotations, and are categorized as Level 2.

15. ENVIRONMENTAL LIABILITIES

The Company has accrued the following discounted amounts for environmental liabilities on the Consolidated Balance Sheets at December 31, 2012 and 2011:

December 31 (millions of dollars)	PCB	LAR	Total
2012			
Environmental liabilities, January 1	199	58	257
Interest accretion	9	2	11
Expenditures	(8)	(10)	(18)
Revaluation adjustment	(3)	2	(1)
Environmental liabilities, December 31	197	52	249
Less: current portion	(13)	(9)	(22)
	184	43	227

December 31 (millions of dollars)	PCB	LAR	Total
2011			
Environmental liabilities, January 1	251	58	309
Interest accretion	12	2	14
Expenditures	(9)	(7)	(16)
Revaluation adjustment	(55)	5	(50)
Environmental liabilities, December 31	199	58	257
Less: current portion	(13)	(9)	(22)
	186	49	235

The following table illustrates the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized in the Consolidated Balance Sheets after factoring in the discount rate:

December 31 (millions of dollars)	PCB	LAR	Total
2012			
Undiscounted environmental liabilities, December 31	233	54	287
Less: discounting accumulated liabilities to present value	(36)	(2)	(38)
Discounted environmental liabilities, December 31	197	52	249

December 31 (millions of dollars)	PCB	LAR	Total
2011			
Undiscounted environmental liabilities, December 31	242	61	303
Less: discounting accumulated liabilities to present value	(43)	(3)	(46)
Discounted environmental liabilities, December 31	199	58	257

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2012 and in total thereafter are as follows: 2013 – $22 million; 2014 – $38 million; 2015 – $36 million; 2016 – $22 million; 2017 – $17 million; and thereafter – $152 million. At December 31, 2012, of the total estimated future environmental expenditures, $233 million relate to PCB (2011 – $242 million) and $54 million relate to LAR (2011 – $61 million).

Consistent with its accounting policy for environmental costs, Hydro One records a liability for the estimated mandatory future expenditures associated with the removal and destruction of PCB-contaminated insulating oils and related electrical equipment and for the assessment and remediation of chemically-contaminated lands.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations and advances in remediation technologies. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, with respect to the PCB environmental liability, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively. The Company records a regulatory asset reflecting its expectation that future environmental costs will be recoverable in rates.

In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future environmental expenditures have been discounted using factors ranging from 3.75% to 6.25%, depending on the appropriate rate for the period when increases in the obligations were first recorded.

PCBs

In September 2008, Environment Canada published its final regulations governing the management, storage and disposal of PCBs. These regulations were enacted under the *Canadian Environmental Protection Act, 1999*. These regulations impose timelines for disposal of PCBs based on certain criteria, including type of equipment, in-use status and PCB-contamination thresholds. All PCBs in concentrations of 500 parts per million (ppm) or more, except for specified equipment, had to be disposed of by the end of 2009, with the exception of specifically exempted equipment. Under the regulations, PCBs in equipment in concentrations greater than 50 ppm and less than 500 ppm, or greater than 50 ppm for pole-top transformers, pole-top auxiliary electrical equipment and light ballasts must be disposed of by the end of 2025.

Management judges that the Company currently has very few PCB-contaminated assets in excess of 500 ppm. Assets to be disposed of by 2025 primarily consist of pole-mounted distribution line transformers and light ballasts. Contaminated distribution and transmission station equipment will generally be replaced or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains PCBs in concentrations of less than 2 ppm.

The Company's best estimate of the total estimated future expenditures to comply with current PCB regulations is approximately $233 million. These expenditures are expected to be incurred over the period from 2013 to 2025. As a result of its most recent cost estimate to comply with current PCB regulations, the Company recorded a revaluation adjustment to reduce the PCB environmental liability by approximately $3 million (2011 – $55 million).

LAR

The Company's best estimate of the total estimated future expenditures to complete its LAR program is approximately $54 million. These expenditures are expected to be incurred over the period from 2013 to 2020. As part of its annual review of environmental liabilities, the Company also reviewed its liability for LAR. As a result of this review, the Company recorded a revaluation adjustment to increase the LAR environmental liability by approximately $2 million (2011 – $5 million).

16. ASSET RETIREMENT OBLIGATIONS

AROs, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate of fair value can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an ARO is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the ARO (with corresponding adjustments to property, plant and equipment), which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired and changes in federal, state or local regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

All factors used in estimating the Company's AROs represent management's best estimates of the costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. AROs are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively.

In determining the amounts to be recorded as AROs, the Company estimates the current fair value for completing required removal and remediation work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 3% to 5%, depending on the appropriate rate for the period when expenditures are expected to be incurred.

At December 31, 2012, Hydro One had recorded AROs of $15 million (2011 – $15 million), consisting of $7 million (2011 – $7 million) related to the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities, as well as $8 million (2011 – $8 million) related to the future decommissioning and removal of two of its switching stations.

The Company's liability for the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities is based on management's best estimate of the present value of the estimated future expenditures to comply with current regulations. In 2010, the Company completed a study with the aid of an expert external consultant to estimate the future expenditures required to remove asbestos prior to facility demolition. The amount of interest recorded is nominal and there have been no expenditures associated with these obligations to date.

In 2011, Hydro One recorded an ARO of $4 million related to the future decommissioning and removal of one of its switching stations, in addition to the ARO of $4 million recorded in a prior year related to the future decommissioning and removal of another switching station. The amount of interest recorded is nominal and there have been no expenditures associated with these obligations to date.

17. SHARE CAPITAL

Preferred Shares

The Company has 12,920,000 issued and outstanding 5.5% cumulative preferred shares with a redemption value of $25 per share or $323 million total value. The Company is authorized to issue an unlimited number of preferred shares.

The Company's preferred shares are entitled to an annual cumulative dividend of $18 million, or $1.375 per share, which is payable on a quarterly basis. The preferred shares are not subject to mandatory redemption (except on liquidation) but are redeemable in certain circumstances. The shares are redeemable at the option of the Province at the redemption value, plus any accrued and unpaid dividends, if the Province sells a number of the common shares which it owns to the public such that the Province's holdings are reduced to less than 50% of the common shares of the Company. Hydro One may elect, without condition, to pay all or part of the redemption price by issuing additional common shares to the Province. If the Province does not exercise its redemption right, the Company would have the ability to adjust the dividend on the preferred shares to produce a yield that is 0.50% less than the then-current dividend market yield for similarly rated preferred shares. The preferred shares do not carry voting rights, except in limited circumstances, and would rank in priority over the common shares upon liquidation.

These preferred shares have conditions for their redemption that are outside the control of the Company because the Province can exercise its right to redeem in the event of change in ownership without approval of the Company's Board of Directors. Because the conditional redemption feature is outside the control of the Company, the preferred shares are classified outside of Shareholder's Equity on the Consolidated Balance Sheets. Management believes that it is not probable that the preferred shares will become redeemable. No adjustment to the carrying value of the preferred shares has been recognized at December 31, 2012. If it becomes probable in the future that the preferred shares will be redeemed, the redemption value would be adjusted.

Common Shares

The Company has 100,000 issued and outstanding common shares. The Company is authorized to issue an unlimited number of common shares.

Common share dividends are declared at the sole discretion of the Hydro One Board of Directors, and are recommended by management based on results of operations, maintenance of the deemed regulatory capital structure, financial conditions, cash requirements, and other relevant factors, such as industry practice and shareholder expectations.

Earnings per Share

Earnings per share is calculated as net income for the year, after cumulative preferred dividends, divided by the weighted average number of common shares outstanding during the year.

18. DIVIDENDS

In 2012, preferred share dividends in the amount of $18 million (2011 – $18 million) and common share dividends in the amount of $352 million (2011 – $150 million) were declared.

19. RELATED PARTY TRANSACTIONS

Hydro One is owned by the Province. The OEFC, IESO, Ontario Power Authority (OPA), Ontario Power Generation Inc. (OPG) and the OEB are related parties to Hydro One because they are controlled or significantly influenced by the Province. Transactions between these parties and Hydro One were as follows:

Hydro One received revenue for transmission services from the IESO, based on uniform transmission rates approved by the OEB. Transmission revenues include $1,474 million (2011 – $1,366 million) related to these services. Hydro One receives amounts for rural rate protection from the IESO. Distribution revenues include $127 million (2011 – $127 million) related to this program. In 2012, Hydro One also received revenue related to the supply of electricity to remote northern communities from the IESO. Distribution revenues include $28 million (2011 – $28 million) related to these services.

In 2012, Hydro One purchased power in the amount of $2,392 million (2011 – $2,401 million) from the IESO-administered electricity market; $10 million (2011 – $16 million) from OPG; and $7 million (2011 – $10 million) from the OEFC.

Under the *Ontario Energy Board Act, 1998*, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and transmitters. In 2012, Hydro One incurred $11 million (2011 – $11 million) in OEB fees.

Hydro One has service level agreements with OPG. These services include field, engineering, logistics and telecommunications services. In 2012, revenues related to the provision of construction and equipment maintenance services with respect to these service level agreements were $10 million (2011 – $7 million), primarily for the Transmission Business. Operation, maintenance and administration costs related to the purchase of services with respect to these service level agreements were $2 million in 2012 (2011 – $2 million).

The OPA funds substantially all of the Company's Conservation and Demand Management (CDM) programs. The funding includes program costs, incentives, and management fees. In 2012, Hydro One received $39 million (2011 – $39 million) from the OPA related to the CDM programs.

The provision for PILs and payments in lieu of property taxes were paid or payable to the OEFC, and dividends were paid or payable to the Province.

Sales to and purchases from related parties occur at normal market prices or at a proxy for fair value based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are unsecured, interest free and settled in cash. At December 31, 2012, the Company held Province of Ontario Floating-Rate Notes with a fair value of $251 million (2011 – $250 million).

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 (millions of dollars)	**2012**	**2011**
Due from related parties	154	156
Due to related parties[1]	(257)	(342)
Long-term investment	251	250

[1] Included in due to related parties at December 31, 2012 are amounts owing to the IESO in respect of power purchases of $199 million (2011 – $209 million).

20. CONSOLIDATED STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (millions of dollars)	2012	2011
Accounts receivable	(30)	(18)
Due from related parties	2	(32)
Materials and supplies	2	(4)
Other assets	(4)	(11)
Accounts payable	(14)	29
Accrued liabilities	10	98
Due to related parties	(85)	61
Accrued interest	10	1
Long-term accounts payable and other liabilities	13	-
Post-retirement and post-employment benefit liability	56	60
	(40)	184

Supplementary information:		
Net interest paid	411	410
Payments in lieu of corporate income taxes	197	80

21. CONTINGENCIES

Legal Proceedings

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Transfer of Assets

The transfer orders by which the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves (as defined in the *Indian Act* (Canada)). Currently, the OEFC holds these assets. Under the terms of the transfer orders, the Company is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. The Company cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. However, the Company anticipates having to pay more than the $1 million that it paid in 2012. If the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If the Company cannot reach a satisfactory settlement, it may have to relocate these assets to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on the Company's results of operations if the Company is not able to recover them in future rate orders.

22. COMMITMENTS

Agreement with Inergi LP (Inergi)

Effective March 1, 2002, Inergi, a wholly-owned subsidiary of Cap Gemini Canada Inc., began providing services to Hydro One. On May 1, 2010, consistent with the terms of the contract, the Company extended the Master Services Agreement with Inergi for a further three-year period. This agreement will expire on February 28, 2015. As a result of this agreement, Hydro One receives from Inergi a range of services including business processing and information technology outsourcing services, as well as core system support related primarily to SAP implementation and optimization. Inergi billings for these services have ranged between $93 million and $130 million per year and are subject to external benchmarking every three years to ensure Hydro One is receiving a defined, competitive and continuously improved price.

At December 31, 2012, the annual commitments under the Inergi agreement are as follows: 2013 – $136 million; 2014 – $130 million; 2015 – $21 million; 2016 and thereafter – nil.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. As at December 31, 2012, the Company provided prudential support to the IESO on behalf of Hydro One Networks and Hydro One Brampton Networks using parental guarantees of $325 million (2011 – $325 million), and on behalf of two distributors using guarantees of $0.7 million (2011 – $0.7 million). On April 27, 2012, Hydro One's highest credit rating declined from the "Aa" category to the "A" category. Based on the new credit rating category, the Company has provided letters of credit in the amount of $22 million to the IESO. The IESO could draw on these guarantees and/or letters of credit if these subsidiaries or distributors fail to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of any letters of credit plus the nominal amount of the parental guarantees.

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for the Company's liability under the terms of a trust fund established pursuant to the supplementary pension plan for the employees of Hydro One and its subsidiaries. The supplementary pension plan trustee is required to draw upon these letters of credit if Hydro One is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure the Company's liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the letters of credit. At December 31, 2012, Hydro One had letters of credit of $127 million (2011 – $124 million) outstanding relating to retirement compensation arrangements.

Operating Leases

Hydro One is committed as lessee to irrevocable operating lease contracts for buildings used in administrative and service related functions and storing telecommunication equipment. These leases have an average life of between one and five years with renewal options for periods ranging from one to 10 years included in some of the contracts. All leases include a clause to enable upward revision of the rental charge on an annual basis or on renewal according to prevailing market conditions. There are no restrictions placed upon Hydro One by entering into these leases. Hydro One Networks and Hydro One Telecom are the principal entities concerned.

At December 31, 2012, the future minimum lease payments under non-cancellable operating leases were as follows:

December 31 (millions of dollars)	**2012**	**2011**
Within one year	10	8
After one year but not more than five years	29	26
More than five years	14	20
	53	54

During the year ended December 31, 2012, the Company made lease payments totaling $9 million (2011 – $6 million).

23. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Business, which comprises the core business of providing electricity transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The Distribution Business, which comprises the core business of delivering and selling electricity to customers; and
- Other, the operations of which primarily consist of those of the telecommunications business.

The designation of segments has been based on a combination of regulatory status and the nature of the products and services provided. Operating segments for the Company are determined based on information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance at each of the segments. The Company evaluates segment performance based on income before financing charges and provision for PILs from continuing operations (excluding certain allocated corporate governance costs).

The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see Note 2 – Significant Accounting Policies). Segment information on the above basis is as follows:

Year ended December 31, 2012 (millions of dollars)	**Transmission**	**Distribution**	**Other**	**Consolidated**
Segment profit				
Revenues	1,482	4,184	62	5,728
Purchased power	-	2,774	-	2,774
Operation, maintenance and administration	402	608	61	1,071
Depreciation and amortization	320	329	10	659
Income (loss) before financing charges and provision for PILs	760	473	(9)	1,224
Financing charges				358
Income before provision for PILs				866
Capital expenditures	776	671	7	1,454

Year ended December 31, 2011 (millions of dollars)	**Transmission**	**Distribution**	**Other**	**Consolidated**
Segment profit				
Revenues	1,389	4,019	63	5,471
Purchased power	-	2,628	-	2,628
Operation, maintenance and administration	422	609	61	1,092
Depreciation and amortization	302	304	10	616
Income (loss) before financing charges and provision for PILs	665	478	(8)	1,135
Financing charges				344
Income before provision for PILs				791
Capital expenditures	810	628	9	1,447

December 31 (millions of dollars)	**2012**	**2011**
Total assets		
Transmission	11,586	10,589
Distribution	8,621	7,594
Other	604	653
	20,811	18,836

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

24. TRANSITION TO US GAAP

The adoption of US GAAP has been made on a retrospective basis with restatement of comparative information to reflect US GAAP requirements in effect at that time. The Company's transition date to US GAAP is January 1, 2011, which is the commencement of the 2011 comparative period to the Company's 2012 Consolidated Financial Statements.

Measurement and classification differences resulting from Hydro One's adoption of US GAAP are presented below. With respect to measurement and classification differences, the tables under the heading US GAAP Differences represent quantitative reconciliations of the Consolidated Balance Sheets and the Consolidated Statements of Changes in Shareholder's Equity, previously presented in accordance with Canadian GAAP, to the respective amounts and classifications under US GAAP, together with descriptions of the various significant measurement and classification differences arising from the adoption of US GAAP. Consolidated Balance Sheets and Consolidated Statements of Changes in Shareholder's Equity reconciliations are presented as at January 1, 2011 and December 31, 2011, representing the commencement and ending dates of the comparative financial year to 2012. There were no measurement or classification differences resulting from Hydro One's adoption of US GAAP on the Consolidated Statements of Operations and Comprehensive Income.

Except as otherwise disclosed in this note, the change in basis of accounting from Canadian GAAP to US GAAP did not materially impact accounting policies or disclosures. Reference should be made to the previously filed Canadian GAAP Consolidated Financial Statements as at and for the year ended December 31, 2011 for additional information on Canadian GAAP accounting policies and practices.

The following table summarizes the increases (decreases) to total assets:

(millions of dollars)	Notes	**January 1, 2011**	**December 31, 2011**
Total assets – Canadian GAAP		17,322	18,368
Deferred debt costs	A	32	32
Deferred pension asset	B	(460)	(466)
Regulatory assets	B	450	902
Total assets – US GAAP		17,344	18,836

The following table summarizes the increases (decreases) to total liabilities:

(millions of dollars)	Notes	**January 1, 2011**	**December 31, 2011**
Total liabilities – Canadian GAAP		11,341	11,914
Long-term debt	A	5	9
Net unamortized debt premiums	A	27	23
Pension benefit liability	B	297	779
Post-retirement and post-employment benefit liability	B	153	123
Regulatory liabilities	B	(460)	(466)
Total liabilities – US GAAP		11,363	12,382

US GAAP Differences

The reconciliations of the January 1, 2011 and December 31, 2011 Consolidated Balance Sheets from Canadian GAAP to US GAAP are as follows:

January 1, 2011 (millions of dollars)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Assets				
Current assets:				
Cash		33	-	33
Short-term investments		139	-	139
Accounts receivable	F	911	(124)	787
Due from related parties	F	-	124	124
Regulatory assets		42	-	42
Materials and supplies		21	-	21
Deferred income tax assets		35	-	35
Derivative instruments	C	-	1	1
Other	C	8	(1)	7
		1,189	-	1,189
Property, plant and equipment:				
Property, plant and equipment in service (net of accumulated depreciation)		12,520	-	12,520
Construction in progress		1,402	-	1,402
Future use land, components and spares		139	-	139
		14,061	-	14,061
Other long-term assets:				
Regulatory assets	B	1,013	450	1,463
Deferred pension asset	B	460	(460)	-
Long-term investment		249	-	249
Intangible assets (net of accumulated amortization)		189	-	189
Goodwill		133	-	133
Deferred debt costs	A	-	32	32
Derivative instruments	C	-	7	7
Deferred income tax assets		19	-	19
Other	C	9	(7)	2
		2,072	22	2,094
Total assets		17,322	22	17,344

January 1, 2011 (millions of dollars)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Liabilities				
Current liabilities:				
Accounts payable and accrued charges	D, F	884	(884)	-
Accounts payable	D	-	125	125
Accrued liabilities	D	-	478	478
Due to related parties	F	-	281	281
Accrued interest		84	-	84
Regulatory liabilities		72	-	72
Long-term debt payable within one year		500	-	500
		1,540	-	1,540
Long-term debt	A	7,278	5	7,283
Other long-term liabilities:				
Post-retirement and post-employment benefit liability	B	980	153	1,133
Deferred income tax liabilities		693	-	693
Pension benefit liability	B	-	297	297
Environmental liabilities		287	-	287
Regulatory liabilities	B	540	(460)	80
Net unamortized debt premiums	A	-	27	27
Asset retirement obligations		11	-	11
Long-term accounts payable and other liabilities		12	-	12
		2,523	17	2,540
Total liabilities		11,341	22	11,363
Preferred shares	E	-	323	323
Shareholder's equity				
Preferred shares	E	323	(323)	-
Common shares		3,314	-	3,314
Retained earnings		2,354	-	2,354
Accumulated other comprehensive loss		(10)	-	(10)
Total shareholder's equity		5,981	(323)	5,658
Total liabilities, preferred shares and shareholder's equity		17,322	22	17,344

December 31, 2011 (millions of dollars)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Assets				
Current assets:				
Short-term investments		228	-	228
Accounts receivable	F	961	(156)	805
Due from related parties	F	-	156	156
Regulatory assets		24	-	24
Materials and supplies		25	-	25
Deferred income tax assets		19	-	19
Derivative instruments	C	-	1	1
Other	C	20	(1)	19
		1,277	-	1,277
Property, plant and equipment:				
Property, plant and equipment in service (net of accumulated depreciation)		13,329	-	13,329
Construction in progress		1,436	-	1,436
Future use land, components and spares		138	-	138
		14,903	-	14,903
Other long-term assets:				
Regulatory assets	B	1,064	902	1,966
Deferred pension asset	B	466	(466)	-
Long-term investment		250	-	250
Intangible assets (net of accumulated amortization)		224	-	224
Goodwill		133	-	133
Deferred debt costs	A	-	32	32
Derivative instruments	C	-	33	33
Deferred income tax assets		17	-	17
Other	C	34	(33)	1
		2,188	468	2,656
Total assets		18,368	468	18,836

December 31, 2011 (millions of dollars)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Liabilities				
Current liabilities:				
Bank indebtedness		39	-	39
Accounts payable and accrued charges	D, F	1,071	(1,071)	-
Accounts payable	D	-	154	154
Accrued liabilities	D	-	575	575
Due to related parties	F	-	342	342
Accrued interest		85	-	85
Regulatory liabilities		25	-	25
Long-term debt payable within one year		600	-	600
		1,820	-	1,820
Long-term debt	A	7,399	9	7,408
Other long-term liabilities:				
Post-retirement and post-employment benefit liability	B	1,040	123	1,163
Deferred income tax liabilities		758	-	758
Pension benefit liability	B	-	779	779
Environmental liabilities		235	-	235
Regulatory liabilities	B	635	(466)	169
Net unamortized debt premiums	A	-	23	23
Asset retirement obligations		15	-	15
Long-term accounts payable and other liabilities		12	-	12
		2,695	459	3,154
Total liabilities		11,914	468	12,382
Preferred shares	E	-	323	323
Shareholder's equity				
Preferred shares	E	323	(323)	-
Common shares		3,314	-	3,314
Retained earnings		2,827	-	2,827
Accumulated other comprehensive loss		(10)	-	(10)
Total shareholder's equity		6,454	(323)	6,131
Total liabilities, preferred shares and shareholder's equity		18,368	468	18,836

The adjustments to the January 1, 2011 and December 31, 2011 equity from Canadian GAAP to US GAAP are as follows:

January 1, 2011 (millions of dollars)	Common Shares	Preferred Shares	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Shareholder's Equity
Canadian GAAP	3,314	323	(10)	2,354	5,981
Other comprehensive income	-	-	-	-	-
Preferred shares reclassified outside shareholder's equity	-	(323)	-	-	(323)
US GAAP	3,314	-	(10)	2,354	5,658

December 31, 2011 *(millions of dollars)*	Common Shares	Preferred Shares	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Shareholder's Equity
Canadian GAAP	3,314	323	(10)	2,827	6,454
Other comprehensive income	-	-	-	-	-
Preferred shares reclassified outside shareholder's equity	-	(323)	-	-	(323)
US GAAP	3,314	-	(10)	2,827	6,131

Notes to the Transitional Adjustments

Under US GAAP, the Company (i) measures certain assets and liabilities differently than it had under Canadian GAAP (see details on each measurement change below); and (ii) discloses certain assets, liabilities and equity on different lines in the Consolidated Financial Statements than it had under Canadian GAAP (see details on each classification change below).

A. Debt Issuance Costs (classification change)

Under Canadian GAAP, costs of arranging debt financing, premiums and discounts were netted against long-term debt. Under US GAAP, costs of arranging debt financing are included in "Deferred debt costs" as part of "Other long-term assets", and net unamortized premiums are included in "Net unamortized debt premiums" as part of "Other long-term liabilities".

At January 1, 2011 and December 31, 2011, the effect on the Consolidated Balance Sheets is reflected by the following increases:

(millions of dollars)	January 1, 2011	December 31, 2011
Other long-term assets:		
Deferred debt costs	32	32
Other long-term liabilities:		
Net unamortized debt premiums	27	23
Long-term debt	5	9

B. Pension, Post-Retirement and Post-Employment Benefits (measurement change)

Under Canadian GAAP, the Company disclosed, but was not required to recognize, the net unfunded status of pension, post-retirement and post-employment benefit obligations on the Consolidated Balance Sheets. Under US GAAP, the Company recognized the unfunded status of pension, post-retirement and post-employment benefit obligations on the Consolidated Balance Sheets with an offset to associated regulatory assets for the transitional fair value adjustments as the incremental obligations are expected to be recovered through future rates charged to customers. The deferred tax assets and liabilities arising on recognition of incremental pension, post-retirement and post-employment benefit obligations and the associated regulatory assets offset each other, with no material impact on the Consolidated Statements of Operations and Comprehensive Income. In the absence of regulatory accounting, the related tax impact on the opening transitional adjustments would result in the recognition of deferred tax assets of $113 million on January 1, 2011 and $224 million on December 31, 2011.

At January 1, 2011 and December 31, 2011, the effect on the Consolidated Balance Sheets is reflected by the following increases (decreases):

(millions of dollars)	January 1, 2011	December 31, 2011
Other long-term assets:		
Deferred pension asset	(460)	(466)
Regulatory assets[1]	450	902
Other long-term liabilities:		
Pension benefit liability	297	779
Post-retirement and post-employment benefit liability	153	123
Regulatory liabilities[2]	(460)	(466)

[1] Represents offsetting regulatory assets for incremental obligations for pension and non-pension obligations of $297 million and $153 million on January 1, 2011, and $779 million and $123 million on December 31, 2011, respectively.

[2] Represents write-off of deferred pension asset regulatory liability under Canadian GAAP.

C. Derivative Instruments (classification change)

Under Canadian GAAP, the Company classified its derivative instruments in designated hedging relationships and in economic hedging relationships under the category of "Other assets" on the Consolidated Balance Sheets. Under US GAAP, the Company has included these balances in "Derivative instruments".

At January 1, 2011 and December 31, 2011, the effect on the Consolidated Balance Sheets is reflected by the following increases (decreases):

(millions of dollars)	January 1, 2011	December 31, 2011
Current assets:		
Derivative instruments	1	1
Other	(1)	(1)
Other long-term assets:		
Derivative instruments	7	33
Other	(7)	(33)

D. Accounts Payable (classification change)

Under Canadian GAAP, trade and non-trade payables were disclosed as "Accounts payable and accrued charges". Under US GAAP, trade payables are recognized in "Accounts payable" and non-trade payables are recognized in "Accrued liabilities".

At January 1, 2011 and December 31, 2011, the effect on the Consolidated Balance Sheets is reflected by the following increases (decreases):

(millions of dollars)	January 1, 2011	December 31, 2011
Current liabilities:		
Accounts payable	125	154
Accrued liabilities	478	575
Accounts payable and accrued charges	(603)	(729)

E. Preferred Shares (classification change)

Under Canadian GAAP, Hydro One's preferred shares were classified as equity, and preferred dividends were deducted from retained earnings and accrued as declared. Under US GAAP, the preferred shares are classified outside shareholder's equity because of conditional redemption features in the preferred share agreement. Under US GAAP, the preferred dividends continue to be deducted from retained earnings and accrued as declared (see Note 17 – Share Capital).

At January 1, 2011 and December 31, 2011, the effect on the Consolidated Balance Sheets is reflected by the following increases (decreases):

(millions of dollars)	January 1, 2011	December 31, 2011
Preferred shares	323	323
Shareholder's equity:		
Preferred shares	(323)	(323)

F. Related Party Balances (classification change)

Under Canadian GAAP, receivables from related parties and payables to related parties were disclosed as "Accounts receivable" and "Accounts payable and accrued charges", respectively. Under US GAAP, receivables from related parties are recognized in "Due from related parties" and payables to related parties are recognized in "Due to related parties".

At January 1, 2011 and December 31, 2011, the effect on the Consolidated Balance Sheets is reflected by the following increases (decreases):

(millions of dollars)	January 1, 2011	December 31, 2011
Current assets:		
Due from related parties	124	156
Accounts receivable	(124)	(156)
Current liabilities:		
Due to related parties	281	342
Accounts payable and accrued charges	(281)	(342)

25. COMPARATIVE FIGURES

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2012 Consolidated Financial Statements.

HYDRO ONE INC.
FIVE-YEAR SUMMARY OF FINANCIAL AND OPERATING STATISTICS

Statements of Operations Data *Year ended December 31 (millions of dollars)*	2012[1]	2011[1]	2010[2]	2009[2]	2008[2]
Revenues					
Distribution	4,184	4,019	3,754	3,534	3,334
Transmission	1,482	1,389	1,307	1,147	1,212
Other	62	63	63	63	51
	5,728	5,471	5,124	4,744	4,597
Costs					
Purchased power	2,774	2,628	2,474	2,326	2,181
Operation, maintenance and administration	1,071	1,092	1,078	1,057	965
Depreciation and amortization	659	616	583	537	548
	4,504	4,336	4,135	3,920	3,694
Income before financing charges and provision for payments in lieu of corporate income taxes	1,224	1,135	989	824	903
Financing charges	358	344	342	308	292
Income before provision for payments in lieu of corporate income taxes	866	791	647	516	611
Provision for payments in lieu of corporate income taxes	121	150	56	46	113
Net income	745	641	591	470	498
Basic and fully diluted earnings per common share *(dollars)*	7,280	6,228	5,727	4,528	4,797
Dividends per common share declared *(dollars)*	3,523	1,500	100	1,700	2,410

Balance Sheets Data *December 31 (millions of dollars)*	2012[1]	2011[1]	2010[1]	2009[2]	2008[2]
Assets					
Distribution	8,621	7,594	6,915	6,481	5,873
Transmission	11,586	10,589	9,820	8,993	7,877
Other	604	653	609	161	128
Total Assets	20,811	18,836	17,344	15,635	13,878
Liabilities					
Current liabilities (including current portion of long-term debt)	1,756	1,820	1,540	1,655	1,300
Long-term debt	7,879	7,408	7,283	6,281	5,733
Other long-term liabilities	4,346	3,154	2,540	2,281	1,721
Preferred shares	323	323	323	-	-
Shareholder's equity					
Preferred shares	-	-	-	323	323
Common shares	3,314	3,314	3,314	3,314	3,314
Retained earnings	3,202	2,827	2,354	1,791	1,497
Accumulated other comprehensive income	(9)	(10)	(10)	(10)	(10)
Total liabilities, preferred shares and shareholder's equity	20,811	18,836	17,344	15,635	13,878

[1] Based on US GAAP

[2] Based on Canadian GAAP

HYDRO ONE INC.
FIVE-YEAR SUMMARY OF FINANCIAL AND OPERATING STATISTICS (continued)

Other Financial Data

Year ended December 31	**2012**	**2011**	**2010**	**2009**	**2008**
Capital expenditures *(millions of dollars)*					
Distribution	671	628	629	643	570
Transmission	776	810	936	918	704
Other	7	9	5	5	10
Total capital expenditures	1,454	1,447	1,570	1,566	1,284
Ratios					
Net asset coverage on long-term debt ratio[1]	1.81	1.81	1.77	1.79	1.84
Earnings coverage ratio[2]	2.83	2.71	2.39	2.15	2.63
Operating statistics					
Transmission					
Units transmitted *(TWh)*[3]	141.3	141.5	142.2	139.2	148.7
Ontario 20-minute system peak demand *(MW)*[3]	24,768	25,505	25,145	24,477	24,231
Ontario 60-minute system peak demand *(MW)*[3]	24,636	25,450	25,075	24,380	24,195
Total transmission lines *(circuit-kilometres)*	29,327	28,942	28,951	28,924	29,039
Distribution					
Units distributed to Hydro One customers *(TWh)*[3]	29.2	29.2	29.1	28.9	29.9
Units distributed through Hydro One lines *(TWh)*[3,4]	42.4	42.5	42.5	43.5	44.7
Total distribution lines *(circuit-kilometres)*	121,525	120,514	123,552	123,528	123,260
Customers	1,381,926	1,365,379	1,345,177	1,333,920	1,325,745
Total regular employees	5,811	5,781	5,717	5,427	5,032

[1] The net asset coverage on long-term debt ratio is calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

[2] The earnings coverage ratio has been calculated as the sum of net income, financing charges and provision for payments in lieu of corporate income taxes divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

[3] System-related statistics include preliminary figures for December.

[4] Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the IESO.